BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

TECHNICAL CONFERENCE ON :

CONGESTION REVENUE RIGHTS :

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Commission Meeting Room

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Tuesday, December 3, 2002

The above-entitled matter came on for technical conference, pursuant to notice, at 9:05 a.m., Alice Fernandez, presiding.

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APPEARANCES:

RICH BAYLESS, Director, Interconnected Systems, PacifiCorp (RTO West)

JOHN P. BUECHLER, Executive Regulatory Policy Advisor, New York ISO

ALAN HEINTZ, Vice President and Consultant to Santee Cooper, on behalf of SeTrans

DAVID LaPLANTE, Vice President, Markets Development, ISO New England

ANDREW OTT, Executive Director, Market Development, PJM Interconnection

RICKY BITTLE, Vice President Planning, Rates and Dispatching, Arkansas Electric Cooperative Corporation

STEVEN T. NAUMANN, Vice President, Transmission Services, Exelon Corporation, Commonwealth Edison, on behalf of the Edison Electric Institute

RICHARD W. OSBORNE, Vice President Power Supply & Engineering, Continental Cooperative Services

JAMES H. POPE, Director of Electric Utility, Silicon Valley Power, Santa Clara, California and Chair, Transmission Agency of Northern California

HARRY SINGH, Director of Market Economics, PG&C National Energy Group

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APPEARANCES (CONTINUED):

DONALD J. SIPE, Attorney, Preti, Flaherty, Beliveau, Pachios & Haley, on behalf of Industrial Energy Consumer Group

DENIS E. WICKHAM, Senior Vice President, Energy East Management Corporation

JAMES BRUGGEMAN, Transmission Engineer, Williams Energy Marketing & Trading Company

JAMES R. DAUPHINAIS, Consultant, Brubaker & Associates, Inc. on behalf of the Electricity Consumers Resource Council (ELCON)

JANICE HAGER, Manager, Rate Design & Analysis, Duke Energy Corp.

JAMES R. KELLER, Director of Policy and Planning, Wisconsin Electric Power Company

PHILIP MESA, Lead Technical Specialist, RTO Project Team, Bonneville Power Administration

MICHAEL G. STAUART, Vice President, Legal and Public Affairs, Wisconsin Public Power Inc., on behalf of the Transmission Access Policy Study Group (TAPS)

DR. FRANK A. WOLAK, Professor, Department of Economics, Stanford University, on behalf of Old Dominion Electric Cooperative

-- continued --

APPEARANCES (CONTINUED):

THE HONORABLE GLEN R. THOMAS, Chairman, Pennsylvania Public Utility Commission

THE HONORABLE SAM J. ERVIN IV, Commissioner, North Carolina Utility Commission

STEFAN BROWN, Senior Economist, Oregon Public Utility Commission (by phone)

WALLACE GIBSON, Manager, System Analysis & Generation, Northwest Power Planning Council (by phone)

ROBERT GRANIERE, Consultant, NRRI (by phone). In person: Raymond W. Lawton, Director, National Regulatory Research Institute (NRRI)

MATTHEW I. KAHAL, Exeter Associates, Inc., on behalf of the Arkansas Public Service Commission

DR. MICHAEL S. PROCTOR, Chief Economist, Energy Department, Missouri Public Service Commission

P R O C E E D I N G S

(9:35 a.m.)

MS. FERNANDEZ: Good morning, and welcome to today's conference, which is on congestion revenue rights. I'm Alice Fernandez with the Office of Markets, Tariffs, and Rates.

With me today are Udi Helman, Derrick Bandera, also both from OMTR; Rob Gramlich from the Chairman's Office, David Mead, and Mark Hegerle, also from OMTR.

Before we get started -- I see our panelists are already there, which is good -- it's always nice when you're doing one of these to see when your panelists are there. Today's conference is going to focus on the transition process to a contract system in a congestion management system that uses congestion revenue rights, CRRs, also known as FTRs to provide customer with protection against congestion charges.

The initial allocation process, the transition process, is very important, because it's basically one of the main ways of ensuring that customers are protected, and that existing customers receive what they are currently receiving, and that there's access to all available capacity, and also that you can minimize cost shifts.

The SMD NOPR, in that one, the Commission laid out a general process for the initial allocation, but left many aspects of the transition process to be worked out on a regional basis.

The NOPR also proposed that for at least the first four years, CRRs could be directly allocated to load, based on the historical use of the system. After that initial period, the congestion revenue rights would either be most likely subject to an auction with the auction revenues given back to load, although there was a potential for a region to explain why a longer transition period was appropriate.

In our many outreach sessions, we've heard a number of concerns, and some of these fall into several general categories. The first is that we've heard a lot of concerns expressed about the potential for an auction; that many parties feel that an auction will not provide them with the same type of protection as a direct allocation of congestion revenue rights.

Second, we've heard concern from certain parties, particularly those in load pockets that are concerned that the initial allocation process may not provide them sufficient protection against congestion, the higher prices they would see under an LMP system.

Third, we have heard a number of concerns about acquiring congestion revenue rights for load growth, either as part of the initial allocation process or after that initial allocation process, how customers would obtain congestion revenue rights in the future for load growth.

And, finally, we've heard -- the NOPR proposed that many of the initial congestion revenue rights would be styled as obligations. We've heard that in some areas of the country, and looking at Rich Bayless, we've heard it in the West as one area; that obligations may not work very well in some parts, and that different types of congestion revenue rights or FTRs such as one styled as options, might work better in terms of protecting customers in those regions and matching existing rights.

Today, we hope to discuss proposals dealing with these issues and with other questions involving congestion revenue rights. We'd like to discuss specific principles that could be included in a standard market design final rule that would be used for the transition process.

Before we begin with the panels, I want to go over a few procedural items. First, recognize that we had a lot of people who requested to speak on the panels today, and we were not able to accommodate all of them. However, we would like input, and to the extent that others have specific suggestions on principles that should be included in the final rule or specific ways that the transition process should be done, we welcome any concrete proposals that are submitted.

Second, I'd like to say that just in terms of we have four panels today, and there are going to be some differences in how the panels are set up. The first panel is basically composed of representatives of various regional organizations.

Some of them have already sort of been there, done that, and been through the transition process; others that are part way through the transition, have proposals in place for the region where they have thought about how to do the transition process within the region but have not completed that yet.

And we've asked them to talk about the process within the region, and because we've kind of given them more of a laundry list of things to talk about, they're going to have seven minutes for opening statements. And, as I've said, we've asked them to get into some details about how the transition process either has been done in their region or is being proposed to be done in their region.

For the other panels, we've asked the panelists to limit their opening statements to three minutes, to allow plenty of time for discussion. With that, I think we're probably ready to get started.

Just in terms of some of the other logistics, something we've kind of used in the past is when we get into the discussion, that the panelists have something they want to comment on, if you'd just put your little tent card up so that we can acknowledge you.

And with that, I'll let the panelists introduce themselves. Since we're alphabetical order, why don't we start with Mr. Bayless.

MR. BAYLESS: All right, thanks, Alice. When you're surfing the web and you find a site that you thing has all the details, you rapidly go there, you pull it up, and it comes up and says Under Construction, it's the same thing here. RTO West is still under construction.

I'm Rich Bayless. I'm going to be speaking for RTO West, but I'm actually with Pacificorp today. Should I go ahead now? Okay.

We are under construction. We think we've got a method for dealing with the CRRs that fits within the SMD framework, although there are differences. I'm going to try to go fast here, because we've got a big clock staring at us right there.

Anyway, in the Northwest, we believe there are some significant differences that we need to watch out for because of the characteristics of the Northwest, which I am going to talk about, and because of the large amount of non-jurisdictional parties that have to be involved in a successful market system back there, that need to voluntarily join.

We're also looking for timely approval process, and we're in eight states and a couple of provinces and with the Indian tribes, lots of different sovereignties. So we're looking for something that we can do quickly.

There's a paper back there -- and I won't go through all of the principles we've put in the paper, but we listed seven principles that we use to come up with some special provisions regarding the transition from existing rights. They involve that the translation of existing rights should not expand or diminish existing rights. We need people that voluntarily join.

We need the conversion to our version of CRRs to be voluntary, and the people with existing rights during the translation must make sure that they bring their item out of congestion management assets to support their preexisting contracts. There are several other principles, but they are along the same lines.

We are going to have a locational pricing methodology. We're going to have a flexible -- you need to understand some of the types. We have two types of services, and they will fall under a flexible, accept all schedules methodology.

If the parties are willing to pay for congestion costs, it's a nodal security constraint, least-cost redispatch, using voluntary ink deck generation bids.

We have two ways to hedge. We're proposing two ways to hedge: One is with firm transmission options, and I'll talk about those in a bit, and the other is with catalog transmission rights, or CTRs.

Both produce credits to offset congestion costs from schedules, and credits only if the schedule is scheduled by the holder of the rights. There's two significant differences between -- or there are significant differences between the two.

FTOs are sort of like CRRs in that they are tradable. You can obtain them by converting your existing rights.

They're obtainable through an action I'm going to term pundling by the RTO, and we'll talk about that. They can be obtained through expansion, bilateral trades, they're a financial right; they're directional; they go between a source and sinks, same pair.

But the holder can actually schedule anyplace on the RTO system and obtain either a full or partial hedge between the source and same pair with the FTOs. So they're an instrument that we believe is more tradeable than what I'll talk about next, which is the CTRs, which are not tradeable at all.

CTRs are used to hedge preexisting contracts whose rightsholders elect not to convert to the full RTO service and covert to FTOs. They're not tradeable; they're only good for the existing rights of the contract between existing source and sinks. They're managed by the RTO in the aggregate and from a pool, and they're meant to get rid of the allocation issue we had.

There are two types of services the RTO offers: One is the full service that allows somebody that pays an access fee that has FTOs can go anyplace on the system and hedge; versus CTR service, which just allows a party to use preexisting sorts of rights, but with the RTO managing those rights through a pool.

To use either type, up front, we're going to have a cataloging process where all the flexibility and optionality and rights in the various contracts are itemized, tested for sufficiency by the RTO, and put into a catalog.

There is a third type of service where a customer can actually take RTO service and step around their PTO and take CTR service, but it's a complications, and we'll talk about it in questions. We're getting short here.

New services take RTO service, which is access fee plus getting FTOs. The RTO, when it takes existing rights and sort of puts them together with CTRs and provides that service, if there's ATC left over, it can take the remaining ATC translated into FTOs and auction those.

This is the sort of pundling, we call it, method, where the RTO that manages preexisting rights for those that choose not to convert, can actually free ATC up and sell through the auction as FTOs.

Special provisions: We've gone to the CTR because in the aggregate, if we had full conversion of all the rights with all the optionalities required for the hydro system, the non-power requirements and all the other things, we ended up being way over-allocated.

The system works now, so we decided that if we can give the RTO that duty, using those that choose not to convert with a more limited service, the RTO can put them together, come up with a service that can meet those requirements.

More flexible service is available to those that choose to use it, and convert to the FTOs.

Load growth. Load growth fits with the FTR method. Loads that are growing have to provide sufficient assets for their load growth. They take preexisting service, ETR service. That sufficiency test is done every so often. New loads that are not covered by preexisting contracts have to pay an access fee and then somehow either expand or obtain FTOs.

There are some things we've got built in that sort of change some of the way the FTO revenues flow. We can talk about those in questions. And I think I'm over.

That's pretty much it. There's a couple of other special provisions. Our flows reverse a lot, and people that have schedules in one direction can see the flows and congestion change on them even daily. We've decided to go with options as opposed to obligations.

And I guess that's about it. The way we get there through transition is that all the rights, pre-888 rights and post-888 rights all will go through the cataloging process and either elect to take CTR service or convert. So that will be our transition.

MS. FERNANDEZ: Thank you. John?

MR. BUECHLER: Thank you, Alice. My name is John Buechler. I'm speaking today on behalf of the New York ISO. I will be addressing primarily the allocation process that has already happened within the New York system for transmission congestion contracts, and so I'll be using that terminology here mostly.

I just wanted to point out, there is a handout in the back of the room. Hopefully there's still some copies left you can follow along which outlines the comments I have here.

At the outset of the formation of the New York ISO, all existing transmission wheeling agreements were in fact cataloged. We came up with nearly 300 existing wheeling agreements, facilities agreements or a combination wheeling and facilities agreements.

In the cataloging, we identified the basic terms and conditions of those contracts, the megawatt amount, point of receipt, point of delivery, the parties to the contracts, obviously the terms, termination provisions and so forth. And in fact, all of those existing contracts are contained within an appendix to the New York ISO's open access transmission tariff.

Next in the process, each of these contracts on a contract-by-contract, point-by-point basis were, let's call it mapped on the New York State transmission system to ensure simultaneous feasibility.

In addition, there was identified existing transmission capacity for native load which largely was representing the use of a transmission owner's own system to get remote generation supplies to load. And that was also included in the identification and listing in the tariff.

And then finally, a check, a simultaneous feasibility check, as I said, was performed to make sure that the transmission system was not in fact oversold. It was close, but it was not in fact oversold by those calculations.

What happened next is that the grandfathered contracts were proposed to be grandfathered in accordance with their contract terms, with a number of very specific exceptions, which revolved around the New York ISO tariff and the LMP system under which it operates.

There was an option, first of all, provided to the contract holders to retain their rights, their physical rights, or to convert those to transmission congestion contracts or TCCs. If you chose to retain the rights, you would not be responsible for paying congestion charges to the New York ISO, but under similar provisions to the physical contracts, basically it was a use it or lose it. If you did not schedule a transaction representing the capacity in your transmission wheeling agreement, in effect others used it and you received no compensation for that.

If, however, you did choose to convert to TCCs, you basically received the same rights and obligations that other TCC holders would receive under the New York ISO tariffs.

In either case, however, the customer, the transmission customer, would continue to pay its embedded cost rate under its grandfathered agreement and would not be responsible for paying the transmission service charge or access charge to the New York ISO.

The provisions also included that these existing contract holders would pay for losses, ancillary services and the NYPA transmission adjustment charge in accordance with the New York ISO tariff provisions.

Finally, each of these contracts would expire upon the retirement of the associated generator or the termination of an associated wheeling contract. So in a sense, similar to what Rich just said here, they were not really convertible. They were tied to underlying power delivery agreements.

After these options were developed, there were basically two categories of contracts to deal with. First of all were the existing contracts among the TOs. In that case, the TOs agreed to all of the prior termination provisions that I just mentioned. In essence, agreed to grandfather firm agreements and to terminate nonfirm wheeling agreements.

In the case of third party agreements, which were where the customer was other than one of the eight transmission owners in New York, these same options were provided as were accepted by the TOs. The NYISO filing initially asked FERC to conform these existing contracts to certain of the provisions of the ISO tariff, which I'll talk about later.

FERC, however, ruled that separate 205 filings were necessary to cover all these contracts. Those filings were in fact made. They were protested by many parties. Several years of litigation settlements and hearings ensued at FERC, in which I had the pleasure of participating, and there was even a court case involved.

In the end -- and the end is not yet here -- FERC has largely upheld the conforming provisions that originally were applied for in these tariffs, and there are still limited third-party issues still at hand.

The next page is a timeline which I don't intend to go through, but it gives you some idea that the entire process in New York from the original TO negotiations to form the New York ISO in the first place in 1994, to just last September when FERC issued a tolling order on the remaining issues, eight years later basically some of these existing contract issues are still pending.

I just point that out to give everyone an appreciation for how difficult and how important it is to resolve these issues as up front as possible.

After the existing grandfathered contracts were dealt with, the election of rights or TCCs was a one-time option that occurred prior to NYISO startup. After this accommodation, any residual TCCs were assigned to the transmission owners, and all residual TCCs were required to be sold either by a preexisting bilateral sale or through the auction run directly by the New York ISO, the first auction which preceded startup.

Existing transmission capacity for native load also was required to be sold in the ISO auction, and in the end, when any of the grandfathered agreements expire, that transmission capacity represented by those contracts also goes into the auction for sale.

Auctions were conducted of varying lengths to accommodate basically the market participants' desires. Initially, a six-month auction was performed because of concerns on both sides, the owners and the customers sides, of not knowing what congestion was going to actually amount to and what the value of the TCCs were going to be.

Since then, we have offered longer term durations up to five years at this point within New York. In addition, we also hold monthly reconfiguration auctions.

Real quickly in my last five seconds, you asked for some lessons learned. And while there certainly are different situations in other parts of the country, I think the general experience in New York should be instructive to most areas.

I think practically speaking, there are at least two practical considerations. First of all, the transmission owners must reach agreement on the accommodation of the contracts that they hold since they do in fact own the transmission assets, and in most regions of the country are still probably the largest LSEs and therefore represent load in that role as well.

Second and equally as important is that the transmission owners need to try and reach agreements or settlements up front with the transmission customers to try to avoid some of the experience that we had and particularly the litigation experience and the time delays that that takes.

Third, I think it's important that the Commission acknowledge the need to conform existing contract provisions to the terms of the SMD tariff in the area of conforming to congestion management system and LMP system, ancillary services, scheduling provisions and losses. Those were the specific areas that eventually were found to conform--needed to conform in New York.

Finally, flexibility should be provided in the auction design as regards the duration of CRRs for the reasons I mentioned previously, and the Commission should allow regional flexibility as long as market efficiency is not jeopardized in the design and allocation of CRRs.

And my bottom line point is we strongly urge the Commission not to revisit approved allocations that have already been in place in existing ISOs.

Thank you.

MS. FERNANDEZ: You don't want to repeat that much fun?

MR. BUECHLER: I could repeat that again.

(Laughter.)

MS. FERNANDEZ: Alan?

MR. HEINTZ: My name is Alan Heintz. I'll be speaking on behalf of SeTrans today. I'd like to thank you for inviting SeTrans to present today.

SeTrans is comprised of municipals, cooperative investor-owned utilities. We filed a proposed market design which details the treatments of FTRs, the allocation and auctions and so forth.

To refresh everyone's recollection, I wanted to give kind of a conceptual overview. First we plan on using the LMP style market, actually fairly close to the SMD design.

First of all, there's grandfathered agreements which are the pre-888 agreements, the nonjurisdictional and wholesale/retail agreements. And they have an option for physical or financial rights due to the numerous possible areas of costs shifts. If the rights are physical, the capacity associated with the agrement will reduce the number of FTRs available.

However, if someone with physical rights is not using them, they do not get revenues. Holders of existing physical rights under grandfathered agreements will have the option to convert to financial equivalent FTRs and we believe the RTOs should encourage such conversion.

Allocating FTRs in a manner that truly matches the existing physical use of the system can encourage that conversion. This may require obligations options or actually more flexible types of FTRs.

The ISA would be -- which is SeTrans ISA -- would be issuing the FTRs to allow the transmission customers to hedge against the congestion costs.

The FTRs would apply to the day ahead market settlement process and the allocation of FTRs would be based on the location of the resources and load points of injection and points of withdrawal and would be in the amount of the forecasted load for network service, including retail load, and the allocations would be based on reservations for the point-to-point customers.

All firm customers may request FTRs, and the FTRs allocated to firm customers both initially and on an ongoing basis are subject to a simultaneous feasibility test.

Any remaining FTRs, residual or headroom FTRs, would be auctioned by the RTO. There would also be periodic auctions to facilitate a secondary market of FTRs. And annually, firm customers can receive additional allocations for load growth or new network resources to the extent that there are FTRs available.

Subsequent allocations cannot reduce prior allocations to preserve the economics and encourage long-term contracts and to avoid a complicated reconfiguration process.

However, FTR allocations based on point of injection/point of withdrawal combinations would be reduced if the associated forecasted load or installed capacity is reduced.

Auctions of FTRs would not be mandatory, and we don't believe they should be mandatory, but should be developed on a regional basis because of concerns of cost shift, enabling legislation and tax consequences of what may be equivalent of round trip trade if what the Commission means by mandatory auction is is that somebody is required to auction off their rights in order to get them back, has to buy them back out of the market, in effect we've created a round trip trade, which has potential tax consequences for the nonjurisdictionals.

And we also believe that the load should have the hedge, not that the load should be required to sell the hedge to market participants, which in effect is what happens in an auction.

Auctions of FTRs should occur by the ISO in terms of all the headroom, in terms of FTRs that are not used, not allocated, should be auctioned. They should be auctioned for periods up to one year, maybe on a monthly basis. And we have not developed the method for allocating auction revenues to reduce the zonal rates. That's one of the notes that we've placed in the market design. We haven't developed that portion yet.

MS. FERNANDEZ: Thank you. David?

MR. LaPLANTE: Good morning. New England is about to implement a new SMD-style market in March. What I'm describing is what we plan to implement in March.

There's a handout that summarizes my remarks, so hopefully people have a copy to follow along.

By way of background, the vertically integrated utilities in New England have divested most of their generation and contracted out most of their retail load obligation to competitive wholesale suppliers. This occurred in the late 1990s.

I will note that Vermont and New Hampshire have not yet divested, so that I don't get any nasty letters.

The design of and the allocation of congestion revenue rights was done with this divested industry structure in place. And the key principle that was used was that the congestion revenue rights should be allocated to those supplying energy to load.

There's really two broad categories: Transmission customers that pay congestion costs, and those are utilities that have not yet contracted out their retail load obligation to wholesale suppliers; and the long-term firm through-or-out transmission customers, so that's one set.

And the other set are congesting-paying, load-serving entities, and that's really a key part of the principle, is that those who are paying the congestion costs get allocated the revenues or the revenue rights.

Now, in summary, the way that we're doing this is through a two-step congestion revenue right allocation process. And I think this is sort of a -- we don't have any lessons learned, but we have something better, which I think is a live experiment of actually allocating the congestion revenue rights through an auction when the market starts. So, hopefully it's going to work, but not having seen it done anywhere, it's a first.

So in the auction, all the capability of the NEPOOL transmission system will be made available in periodic CRR auctions. All the market participants are eligible to bid for the CRRs.

We're just auctioning off obligations. We have had a lot of interest in doing auctions. We don't have that ability yet, but are going to work towards it.

And, of course, it assures that we'll have -- the auction will assure that everything is simultaneously feasible. We're only gong to auction off what the transmission system can support.

And the key part of it is that the revenues from the CRR auction are allocated back to those serving load in the wholesale market. And load will be measured on a monthly basis at the time of the system peak.

One of the benefits of doing this on a monthly basis is that it allows for the retial load-shifting to take place, and that those who are actually serving the wholesale load at that particular point in time, receive the revenues from the auction.

Again, it's the revenues from the auction that are allocated back to load, not the CRRs themselves. We've had some concerns similar to what Alice mentioned earlier, that people are concerned that the auction revenues won't be exactly equivalent to the FTR revenues.

In terms of who gets the money, which is always important, each load in the system is given its proportional share of auction revenue rights from all generators and external nodes, subject to the simultaneous feasibility.

What this really means is that each load in New England has an equal -- a proportional right to all the generators on the system. So if I'm in a congestion system and I want to buy from a generator, a cheap generator in an un-congested system, I have the right -- the same right as any other load to get that generator's output to my load. So it's a proportional allocation, giving each load a fair share.

And the ARRs are calculated by using the clearing prices from the CRR auction being settled, so the ARR value is based on the difference in FTR prices between the source and the sink.

And our market trials and our test results have shown that this is working well, that the load in the congestion areas is receiving, as you would think, more congestion revenue than the load in the un-congested areas.

There are three exceptions to the basic principles that address some of the grandfathering and other sorts of issues that have been raised. One is qualified upgrade awards.

If an improvement is made to the transmission system, then those that own the improvement will receive the increase in auction revenues caused by that improvement. And that is sort of taken off the top from all the revenues.

There are also what we term in New England, excepted transactions, which are those transactions grandfathered when the NEPOOL tariff was created. So these are people that didn't go to the general network service; they had specific point-to-point agreements. And those are grandfathered and given ARRs off the top, as well.

The other pre-sort of grandfathering contracts were called NEMA. That's Northeast Massachusetts Contracts, which are contracts that municipal utilities within the Boston area had for generators outside of the Boston area, and they were also given preference in the allocation of CRRs.

In terms of transition process, some principles that we would recommend that the Commission consider is that those responsible for serving the wholesale load should be allocated the CRRs that are revenues from the auction.

In areas with some vertically integrated utilities, the proposal should assure that the allocation process does not prevent other wholesale entities from competing because they are unable to obtain CRRs and therefore can't compete in the energy market.

I think this is an important point. If the CRRs are just given to a vertically-integrated utility, and there's no process by which people that want to serve that load can acquire the CRRs, competition won't be able to take place.

CRR allocation should not erect a barrier to entry, and, again, because of the whole host of institutional issues which you are very familiar with, I think you need a regional solution that hopefully each region can address its particular contractual structure and institutional structure on its own and come to you with a proposal that meets those principles. Thanks.

MS. FERNANDEZ: Andy?

MR. OTT: My name is Andy Ott from PJM. I appreciate the opportunity to present to you today. The FTR allocation process in PJM, I'll go through a little bit of how it works and the history and talk about some lessons learned, and maybe where we're headed for the future.

The process, really the general principle for FTR allocations in PJM had started as the allocation goes to the network and firm point-to-point customers who are paying essentially the revenue requirement of the transmission system, so those who are entitled to the allocation.

The rights are financial. The pre-'88 contracts were honored. Those contracts had the choice of either converting to the FTR mechanism or staying out of the market.

All FTRs are directional and they are obligations. It was critical, though, that the FTR, the requestor, could decide for themselves whether to request an FTR or not, so the network service customer had the option not to request one, so they didn't have to take on an obligation for a counterflow, so they would get paid for the counterflow energy contract and not have to pay it back in the congestion credit.

All allocation of FTRs are subject to feasibility, of course, in order to not oversell or oversubscribe the transmission system, and ensure the revenue adequacy of the system.

The FTR allocation rules in PJM started out -- the fundamental philosophy was try to come with an allocation scheme that mirrored the historical deliveries. So we had tied the source of the FTR -- had to be a unit-specific resource in PJM, which essentially means the unit that was designated to or contracted to a specific load.

And then that load had to be the sink. So the allocation rules were very specific that you had to source at the unit, at the generator location and sink at the load. You couldn't just request the best FTR that you could find. So those allocation rules actually served us well for their time.

The allocation is performed every year. The reason we had it reoccur every year was to allow for flexibility in changing as system conditions changed, and also to accommodate load growth.

I'll talk in a few minutes about where we're headed with that. It looks like that will go longer.

The allocation was up to peak load. So you could only request FTRs up to essentially the peak load, which was the same, again consistent with you were paying for the transmission service based ont the peak load.

There really was no load diversity issue in PJM that had come up during the process, simply because most transmission rights requestors really didn't ask all the way up to their peak load because they were obligations, so some of the rights would be left un-requested, because they were from high-cost areas to low.

That being said, the recognition that there are two ways -- or at least two ways to hedge congestion. Obviously one is to get an FTR, CRR, or whatever we call it. The other is to essentially write what I will call a long-term energy contract with a local generator.

So that recognition that there were two different ways to protect from congestion, really was fundamental to how participants actually utilized the system.

If we talk about lessons learned, probably the most fundamental lesson is the realism that a financial right with the ability to self-schedule the supply or self-schedule the generator, was equivalent to a physical right. But having it as a financial right made the system actually be able to be operated reliably, meaning that you could have an LMP type system with a dispatch and you didn't have to worry about painting megawatts with a physical rights system. It just wouldn't work.

The other lesson we learned is the allocation process really has to evolve as the market matures. I think what we saw, we started out with a shorter-term allocation, you know, just two months, to allow people to understand. And I think we recognized this around the country, you have markets where markets never existed before.

People have to be able to value these paths, so they -- you can't walk in for five years when you first start the market, because you simply have to get some notion of what these paths are worth. So that process of allocating -- we allocate for two months to start with, and then for a year.

And then eventually as we move forward, we expect that the allocations will actually become longer, multi-year. I think there's this tension between the desire to have long-term allocations, but the recognition that you need to evolve into it, if you will.

One of the examples of evolution also was the accommodation of the retail choice. When PJM first had the allocation, the preexisting FTRs that went from year to year had priority.

We eliminated that priority because it was creating a barrier to entry, if you will, for the retail programs. So the concept that the actual FTRs should follow load was fundamental to the principle, and we had to evolve the allocation to recognize that.

As we look out, we actually had the first year of our operation where we did not have an FTR auction. Then we implemented an FTR auction that was a residual auction.

We found that was very beneficial with a lot of flexibility. There was essentially about 13 percent of the system that was unsubscribed that first year because there was really no way for people to subscribe it, because there was no system to auction off the rest.

As we look forward, we look towards moving towards an annual FTR auction. People have asked the question, do we need to choose between auctions and allocation? And I submit that we don't have to choose between the two.

If you allocate the rights to the auction revenues, as we have heard today from other speakers, and those people with the allocated auction revenue rights have the right of first refusal, if you will, to purchase or get -- convert that right in the auction, directly to an FTR.

Then they really are able to protect themselves and get their hedge that they need, because they have that right of first refusal.

Market power concerns, really, in this case, I think they can be mitigated through mitigation procedures. Denying the flexibility of an FTR auction really shouldn't be the consequence of concern over market power.

One other area that we are exploring is the FTR option product. That is coming in along with the auction, and that is essentially to allow people to convert their allocated auction revenue rights into a much more flexible hedging product. So you have your on-peak/off-peak; you have the option, FTR option, which is the type of FTR that has no downside risk.

So those kinds of flexibilities can only really be achieved, if you will, through an auction mechanism.

I think I might be done. Thank you.

MS. FERNANDEZ: Does anyone want to start out the questions?

MR. MEAD: As I listen to the presentations, it struck me that there was a fair amount of differences among the speakers in the way that you either are allocating, if I could use allocation as a generic term to mean, you know, how you give out the transmission rights, as well as some of the specific features of your particular transmission rights.

And I would like to explore for a minute, the extent to which you think a regional variation would be acceptable, first with respect to the allocation issue, and then maybe later on we can talk a little bit about whether there are particular characteristics of transmission rights for which we could allow regional variation, versus what needs to be standardized.

But could I ask the first question to whoever wants to talk first: Can we allow or how much regional variation can we allow in the allocation of transmission rights?

MR. BEUCHLER: Well, I'll try to start off here, Dave. I think in the allocation, the first issue that you deal with is -- or maybe the primary issue is equity, and that certainly varies among regions.

You have people with differing histories, with differing lengths of existing contracts, with requirements-type contracts, with a whole variety of things that differ in different regions, and I think that in the allocation process, you need to let each region come to an equitable agreement that works for them.

I don't see that that would be a conflict for adjacent regions' markets, for example.

MS. FERNANDEZ: I'm sorry, I didn't see your card.

MR. OTT: I think really that regional variation is probably going to be necessary to, at least in a transition period, to recognize that historical contracts in some areas may be different than others.

But I think one of the issues is the allocation process or procedure shouldn't act as a barrier to what I'll call development of a competitive market. So I think that where you really draw the line there in regional variation is the allocation process has to allow enough ability to evolve into a competitive market, meaning that if you allocate physical rights, for instance, or you allocate all the system as options where, you know, the system can be really totally locked and really no market can then develop because it's a barrier to any new entry, that would be where I would draw the line.

MR. O'NEILL: May I ask a question? Some of you have physical rights and others don't, and I guess Alan said that he did. Can you tell me what the difference between a physical right and a financial right is?

MR. HEINTZ: Well, for example, a financial right in the SeTrans proposal would clear in the day-ahead market, so you are totally un-hedged with respect to the real time, any differences between real-time and day-head, where the physical would have that hedge in the real-time as well.

MR. O'NEILL: Now, you can set up hedges for real-time in the financial markets. I mean, they do it in PJM, so there's no -- the financial market can be hedged in the real-time market, so I don't think that's a difference.

MR. HEINTZ: In terms of the package that we put together with the SeTrans, you would have in a -- grandfathered agreements would have the right to continue to stay grandfathered.

MR. O'NEILL: Can you withhold physical rights from the market?

MR. HEINTZ: No, because the RTO has the ability to go ahead and auction off the unused.

MR. O'NEILL: In the real-time dispatch, so that you can't withhold?

MR. HEINTZ: That's correct.

MR. O'NEILL: And if you had the virtual bidding that PJM, and, I believe, New York allows, you can actually preserve those rights until -- your financial rights, till the real-time market, so are there any other differences between financial and physical?

MR. HEINTZ: Well, the flexibility would be in terms of the -- no, actually, I think they are similar. I don't --

MR. O'NEILL: I don't want to put you on the spot, but I would like to learn or understand the differences, if there are any, because some of us on Staff are confused, because when we look at the process, we don't see a lot of differences, and sometimes none at all, given if you include certain types of bidding procedures.

Would anybody -- Rich, do you have physical rights?

MR. BAYLESS: We have financial rights in that all schedules are accepted, and either FTO holders or CTR holders get credit against congestion costs.

FTOs, I think, only provide the hedge up into day-ahead. If there is an existing right because of the way that the bilateral contracts are with hydro that needs flexibility after prescheduled time --

MR. O'NEILL: Can those cataloged rights be withheld from the market?

MR. BAYLESS: The RTO has to make sure that that flexibility can be seen, and it's more or less a financial hedge then after preschedule into real-time. But it's still just a credit. It's basically a financial hedge in that they allow for that flexibility.

Everybody can schedule, so we view it as a financial right. See, back on the question of the transition and our variations allowed, we feel pretty strongly that they need to be at least over the transition period, to keep from having cost shifts and to manage and get all the parties that we want to have in the market, feel comfortable enough that they can get there.

Our transmission system has been graded and operated over the years where we haven't seen a lot of expansion. There isn't a lot of transmission line around. We've got a lean system in the East, and we've got a system designed for the hydro variability in the western part of the system.

And with the high level bilateral contracts, it's been used about as optimally as you can think of. Even the ratings use nomigraphs to exploit the diversity and how we can rate paths, let alone use them.

So we think we can get to where the markets are going, but we're going to need sometime to manage the transition.

MS. FERNANDEZ: Anyone else? I think David had --

MR. LaPLANTE: John made the point that equity needs to be involved, and I agree strongly with what Andy was saying, that you need to have efficiency considerations in the initial allocation.

It shouldn't be frozen in time. It's something that needs to be evolved. You don't want to permanently allocate all of the CRRs to a particular entity, which would stifle competition.

So I think that's one of the key principles, but each region is going to get there differently because of all of the issues and history that they have.

MR. O'NEILL: Maybe you don't want to do it permanently, but how long a term do you think is appropriate?

MR. LaPLANTE: I think that would depend on what the process is for acquiring them after the initial allocation. If the process for acquiring them after the initial allocation is viewed as equitable, then I think it's fine to do it for a reasonably short period of time.

In New England, we're actually allocating them for a month on the first. We're doing a series of monthly auctions so that people can understand what happens. And then we'll do a six-month and then an annual auction.

MS. FERNANDEZ: I think Kevin had a question.

MR. KELLY: Good morning. I have been concerned about simultaneous feasibility, and I suspect that later panels may raise this a lot, and many of you have dealt with it.

But the way I think of the problem is that there's a time diversity in load. Now, you think that the ski resort uses capacity in the Winter, the amusement park in the Summer.

You can meet both their needs until you try to give them out rights and there's not enough rights to satisfy both. And it's not only seasonal; it could be monthly or weekly or even daily.

The example I made up for daily is, you could have Las Vegas factories using power in the daytime and the casinos at night. But when you try to give out all the rights, they just don't add up.

Among the panelists who spoke, I think Rich Bayless said that in the Northwest, the rights are way over-allocated, but he described some process for kind of letting the RTO figure it out.

Mr. Beuchler said that simultaneous feasibility was assured in New York, but I think you said just barely; you kind of just made it, indicating that with a different system, you might not just make it; it could have been a real problem for you, but, by luck, wasn't.

Mr. Ott said that there's no load diversity issue in PJM because most people did not request FTRs up to their peak, which suggests that for some reason, maybe the problem is more theoretical, if you assume people request peak loads, but in practice, may not be.

And I just wanted to have the panel explore that, because I think later panels will raise it as an issue, and maybe I would just ask those three people to comment initially on how they dealt with it, and then others join in, if you care to, starting with Mr. Bayless, then Mr. Beuchler, and then Mr. Ott.

MR. BAYLESS: Well, we know that the system operates now without a lot of curtailments or congestion, so we know the preexisting bilateral contracts work today.

And we actually did this exercise. We went through and took the contracts and looked at all the optionality and the various provisions, and we said, well, if we issue FTO strips for the maximum flexibility and number of rights, the different points of delivery and so forth and the optionality --

We have a Christmas tree diagram, as we call it. It's about four times over-allocated. If we start then taking and looking at the given amount of load in an NT contract and locking in some of the optionality, it gets smaller and smaller.

So it gets down to how are we going to chop up the FTOs and issue them? How are we going to account for a lot of the netting that gets done with the existing control areas, and how are we going to capture the diversity?

Now, we could go through a very complicated, up-front feasible dispatch process that tried to do all that and allocate it. To get where we wanted to go, we figured what we do, instead, is come up with a method that we'd give the rights through the catalog through the RTO to manage in aggregate.

For those that choose not to convert, the service that they get for not converting is much more limited than those that choose to convert to FTOs. But for those that choose not to convert -- and we've got a lot of customers that aren't jurisdictional, that may choose that -- the RTO could take those rights, check them for sufficiency, make sure they have enough assets, and actually start the process of a feasible dispatch sort of solution.

And then they take and manage those in a pool, so it's out of the hands of the individual preexisting rightsholders to use those to horde, and it's in the hands of the RTO to make it used with a minimal set of rights needed.

MR. KELLY: So, just to clarify, where, in theory, you might think that maximal conversion to rights would be the most efficient, at least in your situation, if that were the case, it would be perhaps disastrous and you would encourage less than full conversion; am I hearing you correctly?

MR. BAYLESS: Well, we're trying to provide incentives for people to convert, but we're also trying to give those that think they need not to convert, a method.

MR. HEGERLE: But what happens if there are insufficient assets?

MR. BAYLESS: If there are insufficient assets, the preexisting rightsholders have to bring them or the RTO can actually cause them to be brought.

MR. HEGERLE: What do you mean by "bring them"? To build? Is that what you mean by that?

MR. BAYLESS: Build or bring whatever assets need to bring the requirements up.

MS. FERNANDEZ: And when you're talking about assets, is this basically transmission assets?

MR. BAYLESS: Wires. It can be re-dispatch. It could be remedial action schemes, but it's mostly wires.

MS. FERNANDEZ: Okay. If the parties that are sort of in the CTR -- the one where it's grouped.

MR. BAYLESS: Yes?

MS. FERNANDEZ: If they convert to the FTO, what type of rights would they get?

MR. BAYLESS: Then they go through the up-front feasible dispatch and lock in optionality, and they get an instrument that they can trade and manage themselves, if you will.

And it gives them a financial hedge between a point of injection and withdrawal as a point-to-point might have converted. But it allows them to schedule. They can schedule anyplace on the system and get whatever the congestion costs might be between that pair of source and sink, os it's a flexible product that they can easily trade.

MS. FERNANDEZ: Okay, but in terms of the level of the amount, I mean, if you couldn't satisfy all of them, as is, if they decided to convert, what type of -- I mean, would they only get a partial coverage?

MR. BAYLESS: I depends on the situation. As they're mapped, we would probably chop them up so there would be an on-and-off-peak monthly feasible dispatch done. The characteristics that pertain to the particular contract would be itemized in the catalog, and if there were any other concerns that happened to be required of that contract in the translation, that would have to be made.

We think that as they actually get close to using the preexisting right -- I mean, it works today. So they actually get the rights to serve what they actually have to. And we think that if you do the feasible dispatch and the translation process correctly, they'll get what exactly they need. And should it be not exactly what they need, they can trade, go out and find some others that will suffice.

MR. HEGERLE: Just to clarify, would you be cataloging if there were sufficient transmission or other assets available?

MR. BAYLESS: Say it again?

MR. HEGERLE: Would you be doing the cataloging process if there were sufficient transmission assets available to manage the congestion? Is it really just a product of not having enough?

MR. BAYLESS: I believe we'd still do the catalog. The catalog is going to be used for a lot of different purposes, but it'll give the RTO actually a tool to see what people are bringing to the sufficiency test and so forth. So, yes, I think we would.

MR. KELLY: Well, can you determine if there's enough without doing the catalog, or is that a step toward making --

MR. BAYLESS: No. That's a first step. Then sufficiency tests wold be done off of that.

MR. KELLY: Just before we go to Mr. Buechler, are you convinced that this is a solvable problem or likely solvable?

MR. BAYLESS: The system works. We think we can get there. We think it's solvable.

MR. KELLY: Thank you.

MR. BUECHLER: When I mentioned that the initial allocation check served certain paths anyway were just about there, that was with reference to the existing transmission wheeling agreement, that universe of contracts and rights with the provisions for termination and those rights going into the auction.

At this point I think we have in the area of two-thirds of the transmission capacity that's actually in the auction process. So by self-determination, all these grandfathered agreements eventually will wind up in the auction process. And so the situation is getting better, if you will, essentially has gotten better over the past couple of years.

MR. KELLY: Thank you. Mr. Ott?

MR. OTT: Yes. I think one of the issues of feasibility is recognition that there are certain, again if you're comparing history and evolution to a market system, there are certain areas, you know, in PJM it would be the Delaware area or the Newark, New Jersey area. In the West it would be San Francisco. There are certain areas where there's just not enough transmission capability to serve all the load in that area.

So fundamentally, that load will recognize that, again, they have two ways to hedge themselves. One is to write energy contracts, contracts for difference if you will between local generation and load. The other will be obviously to acquire CRRs.

So the concept of the feasibility of the transmission system being able to support what I'll call traditional deliveries is probably going to be recognized in these areas.

But I think the other concept, though, you know, there's a tendency to want to essentially take existing utilization patterns and set them in stone and keep them forever. And again, that kind of allocation procedure would tend to -- the customers may not see the efficiencies of the system, meaning they wouldn't face the prices or the spot prices to see the system being used more efficiently.

But I think the other concept though is the recognition that for instance, a multi-period type FTR allocation or auction.

For instance, in the West, we have what I'll call very dramatic seasonality changes. So you may have a very different pattern in the spring because of the meltoff than you would in the summer type situation.

So you could still have a long-term transmission allocation or auction, but the allocation would recognize the seasonal variation, meaning you'd get your spring rate, your summer rate, your fall rate, et cetera. So you still have a feasibility across the whole year. But the rights would actually evolve through the year as the system flow dynamic changes.

It so happens we have that and I know New York has the technology and PJM has purchased it also to have multi-period FTR auctions, which essentially are very similar, where you can auction for one month, two months, six months or fall/winter/spring, but still have a longer-term type, so that the customer has the ability to lock in and the RTO has the ability to test feasibility over a longer period under changing conditions.

So I think those kinds of things can make all this work and make these problems solvable. I hope I answered your question.

MR. KELLY: Yes. Thank you. I'd give the other panelists a chance to comment because as I've traveled around the country, this has been one of the biggest issues I've heard from those parts of the country that have not had this kind of market force. The biggest question mark is will there be enough CRRs to go around.

People tend to be comfortable if they think there would be, but they're afraid there won't be, and we'd just like to hear your either experience or advice on how to make sure it's not a problem.

MR. LaPLANTE: In New England, people are comfortable that the typical peak load day is used to model the transmission system and the auction will give them the rights they need. So it's fairly traditional load shape, so the peak load is a good representation.

MR. HEINTZ: Well, I think that it's an issue of regionality. For example, your example was actually more retail wheeling related in terms of a ski resort verse I believe it was an industrial.

MR. KELLY: I used that just because it was --

MR. HEINTZ: Oh, no. I understand.

MR. KELLY: Kind of easy to understand. But it's certainly the same issue for wholesale wheeling.

MR. HEINTZ: But to the extent that the load is not that diverse when it's aggregated with the LSEs, you have less of an issue with that. And I think that's an issue for regionality. Where you do have LSEs with significant load diversity, that's an issue in that region that needs to be addressed. To the extent you don't have it, then it may not be addressed in that same manner.

MR. KELLY: Thank you.

MR. GRAMLICH: I was waiting for Kevin to go first because I was going to preempt his question that he's been using in other panels. What should the final rule say? I think we've heard five voices of support for the idea that on this issue, regional variation would be fine and would not hinder efficiency, would not create seams problems. And in fact I think there are five Commission-approved ways of doing this for each of you, two of which have been issued after the NOPR.

That said, there is a bit of a tension here. John warned us all that in New England after eight years of litigation, it would make a lot of sense for these issues to be resolved up front as cleanly as possible. So I wonder should there be a set of principles that should be used that should be standard?

I've heard four or five this morning so far. Maybe we could develop more consensus on those as we go forward. But things like cataloging existing rights, don't diminish existing rights to the system. Rights should be simultaneously feasible. Don't permit permanent allocation to one entity right off the bat. The rights should follow load. I mean, these are some principles that various people may agree or disagree with. But is that what the final rule should look like, focusing on principles like that?

MS. FERNANDEZ: Any volunteers?

MR. BUECHLER: Yes. I guess I would endorse those types of principles. I might add that I would not advise that there be an absolute prohibition against allocation versus auction, but that in my view an auction should be required, at least a residual action, as a means to provide some price transparency and have a centralized process, that really only a single entity in the ITP is the most obvious choice to me anyway to conduct that, would be able to ensure the simultaneous feasibility and in an impartial manner, you know, for the future to provide access to anyone that wants to participate in the auction.

MR. HEINTZ: I think that first of all you want to match the FTRs and the physical historical uses as much as possible, and that requires I think differences in terms of certain contracts are done certain ways in different regions. The Commission has actually accepted certain types of contracts in certain regions but not in others in the past as well.

You have issues with respect to people that have next-to-native load firmness. Do they receive the full FTR and the native load that had the first rights on that doesn't?

There's an issue of matching to make sure that you don't have the cost shifts. And I think each region will end up probably having it done slightly differently with respect to the FTRs that the LSEs or the load would would be receiving the benefits of them, and I do agree that the residual auction should be required in order to get them out there, but not a mandatory auction of all rights.

MR. LaPLANTE: I agree with John and Alan on the requirement for at minimum a residual auction. I think the rule should also define the CRR product in detail, exactly what it is and what you get for it so that you've got a similar product throughout the country.

And also exploring the treatment of physical rights and trying to essentially come up with a standard physical right, if that's possible, I think would be a contribution to make things go more smoothly as well so that people know what they're buying or what the products are.

And then the allocation can be based on the various contracts and firmness and whether the industry is vertically integrated in a particular region.

MR. MEAD: David, let me just follow up for a second. When you say that the final rule should define the CRR product, are you suggesting that there are certain characteristics of CRRs that should be standardized across the country?

MR. LaPLANTE: You're buying the same. It is the right to receive the revenues from point to point. Exactly what is a CRR? You need to lay out -- and it should be the same throughout the country.

MR. MEAD: So that, for example, you would be uncomfortable with the kind of financial transmission option that is in RTO West existing anywhere in the country?

MR. LaPLANTE: I could see where you would have an obligation or an option available as two separate acceptable products. But both of them should be -- they should be the same throughout the country; that they give you the right to the difference in congestion costs between a source and a SYNC.

If there's something different than that, then I think it should be brought out and perhaps standardized.

MR. GRAMLICH: So standard products, plural?

MR. LaPLANTE: Yes.

MR. O'NEILL: What about the flowgate rights?

MR. LaPLANTE: I never understood what a flowgate is so I may not be the best person to answer this one.

(Laughter.)

MR. O'NEILL: Andy posts prices for them in PJM I think, don't you, Andy?

MR. OTT: Shadow prices, yes.

MR. LaPLANTE: But conceptually, it could exist over flowgates as well. You'd go from hub to hub to a SYNC, hub to a source or over a gate. But the product is really what are you getting?

MR. OTT: What should the final rules say? Obviously I think the product standardization, you have an obligation-type product point-to-point. You have an option-type product. I think that would be helpful to have the product standardization.

The flowgate product I believe is more elemental. I personally think a point-to-point right will be the one that will be most requested. I don't think you should require a flowgate rate necessarily, but you should allow for it too.

But I think really you need to have some sort of option, and I think you need to promote what I'll call price discovery, efficiency, the ability to have parts of the system that are laying unused in the allocation process to be able to be auctioned off and utilized.

I think the concept or the principle of you can allow regional variation, for instance, in the allocation process. But I think there are fundamental principles about the allocation process, meaning it can't act, again, as we had talked about, it cannot act as a barrier to entry to development of a competitive market. The products that you're allocating have to be able or be consistent with what I'll call the hedging products, you know, the point-to-point obligation option, that kind of thing.

The concept that the rights are financial, having again the financial right with the ability to certain schedule alternatives like self-scheduling, supports what I'll call the real time dispatch philosophy. In other words, my dispatchers don't know who owns transmission rights. They don't need to know that. They're busy working on the real generators and the real loads on the system and maintaining reliability.

Those financial contracts have to stay out of the physical dispatch. I think those kinds of philosophies are fundamental. You have to have that information in the rule.

As far as a specific allocation process, probably that will evolve and probably will evolve differently, and I assume that's okay as long as the allocation doesn't what I'll call cripple the market. In some of these areas where the system is way oversubscribed, you've got to deal with it.

And maybe there's guidance needed in the final rule. How do deal with an area where the system is way oversubscribed? I know in the NOPR you had thrown out the concept of the transmission owner who sold the service would be, that's a way to do it. But certainly the rule needs to deal with the issue of oversubscription.

MR. BAYLESS: In the Northwest -- what I've just heard is a bunch of principles. I think we believe that the order should talk about principles and give the region an opportunity to figure out exactly how to meet the requirements in the principles.

We also hopefully can have some deference on the process to get there. We think the CTR pooling is going to let us get there the quickest.

As far as what should be standard, if you convert, and in our case we convert to options, as long as the mechanisms that we're defining by that fit within the framework and fit within sort of a standard issue product, I think that's what needs to be done.

We're going to have to chop our FTOs and shape them to make sure that there's enough and they can be used in the ways that people will value them, and I'm not sure a standard issue from the East Coast would fit the West Coast in that regard.

But I think mechanically, the mechanisms and the principles I think we can meet.

MS. FERNANDEZ: In terms of the principles, the principles sound like you could have ones like you basically try and convert existing rights. You don't diminish existing rights. And you don't get more than you already have now. And those seem to be sort of general equity principles that you could incorporate in a rule. Is that some -- I mean, I think in terms of when we're talking about some of the principles, you could lay out these sort of very general principles that say, you know, you must do this, you must have rights that are simultaneously feasible. That sounds like another one.

(Panel nods in the affirmative.)

MS. FERNANDEZ: I'm getting nods from -- you should have some type of auction, even if it's a residual auction?

(Panel nods in the affirmative.)

MS. FERNANDEZ: Trying to look at some of the other ones. Another one I've heard is that the right should follow the load so that if people want to change suppliers, there should be something built into the systems that can do that.

(Panel nods in the affirmative.)

MS. FERNANDEZ: And it is products. That there could be different ones, but those should be defined so that what is a financial right in one system, a financial obligation in one system is basically going to be the same as a financial obligation in an adjoining system.

You could have obligations and options, and those could be separately defined products, but if you buy an option, you know what it is, if you buy an obligation,you know what it is. That seems to be another general principle.

(Panel nods in the affirmative.)

MS. FERNANDEZ: Are there other ones?

MR. HEGERLE: One thing I was wondering about, and maybe it's implicit in what you said but nobody has said it directly is what do you do with load growth? How is that addressed? If we could just sort of walk down the line. How would you do that?

MR. OTT: Today in PJM, since we have an annual allocation process, the load growth for that year is on par with everyone else to receive an allocated share of rights.

One way, if you had a longer term allocation procedure. Again, just because you have a long-term allocation procedure doesn't mean you're going to allocate the same right for the whole period. So you could account for projected load growth and allow those allocated rights to actually stack up over time.

So I think it's manageable.

MR. HEGERLE: So you could use something like -- the current network contracts have a ten-year forecast of loads and resources. You could build off of something like that?

MR. OTT: Again, the dichotomy of you want short-term, at least people seem to want yearly allocations to be able to adjust themselves to changing conditions, but they also want and need the ability to lock in long-term.

So one way to deal with that is to allow a long-term lock-in, but you do a multi-period type either allocation or option, but you look at each year and allocate a different set of rights for that year on a long-term basis.

Then you have the yearly configuration, so the whole concept of accommodating load growth and still having a long-term lock, I think, can be accommodated.

MR. LaPLANTE: The auction revenues will be allocated, based on the actual peak load in a month, so as load grows, if one load is growing faster than another, they will get a large allocation, so it's sort of self-correcting in the revenue allocation process.

MR. HEINTZ: By allocating the first round -- and there you have your current load, the forecasted load for that year -- then in subsequent rounds of allocation, anybody who has a point of injection or point of withdrawal pairing that is being reduced, would actually free up some more FTRs that would be available.

You'd also have the residual FTRs, and the load growth would then be able to nominate those and go ahead and receive the allocation. And the current allocation would not upset the prior allocation, so that you do have a hedge for the long-term resource planning that the load has entered into.

In other words, if I have made decisions on certain resources for certain load, that prior allocations don't upset that economics.

MR. BEUCHLER: Relative to load growth, I'll support what Andy and Dave have both said. We have similar types of workings on a seasonal basis and going out for multi-years at this point.

A related point and a comment that Alice made a minute ago about rights following loads. I just would point out that there is flexibility needed in that area as well, because there are different ways of accommodating that, something that I don't think has been mentioned here.

But in New York, the auction revenues go back to credit the transmission service charge or the access charge, and in that manner, the revenues, if you will, go back to loads or really the users of the transmission systems, which are both the native loads of the transmission owners, as well as the through-and-out transmission customers as well.

So, we think that's a method of assuring that principle, but it wasn't exactly clear.

MS. FERNANDEZ: I understand the principle. It seemed to me that what we'd be talking about is that if load wanted to buy from differing sellers, that it should be able to continue protection, and that -- when I'm saying that the rights follow the load, one way of doing that is reallocating the rights.

I think what you're talking about is another way, because the transmission --

MR. BEUCHLER: I'm not talking about reallocating rights, not for that purpose.

MS. FERNANDEZ: One other area --

MR. HEGERLE: I don't know if Rich had anything to add to that.

MS. FERNANDEZ: I'm sorry.

MR. BAYLESS: We have four ways to do it. If a preexisting rightsholder, wherein the rights, the load growth is covered, and they choose not to convert, and they take CTR service, then their assets will be checked periodically through sufficiency tests. And if their load grows and their assets aren't covering it, they will have to expand the system.

And the PTO can back that up, or the RTO can back that up if the PTO fails. If they choose to convert because they are going after different units or something and they want to go to different places, they can choose to convert and use their FTOs to hedge other things, and then they are converted, or they taking regular RTO service, so they would have to then either obtain more FTOs for future load growth and so forth --

New loads that come on that aren't covered by preexisting contracts, would take new RTO service and they would pay the additional access fee, and they'd have to find FTOs. If they expand the system, they would be allocated FTOs; if they helped to expand it.

Native load that's not covered by specific contracts right now would be treated and translated as a network type transmission service customer.

MR. HEGERLE: Thank you.

MS. FERNANDEZ: Actually, I was looking at my notes and there's one more area where I think I've heard a lot where I'd like to see if we have consensus on, and then there's another topic that we haven't really talked, I think, as much about.

And that is that I have heard a number of the speaks talk about there shouldn't be a prohibition on auctions versus allocations. Is that a principle that should be included in a final rule?

Basically, that's something that should be left to regional choice?

MR. BAYLESS: We'd agree.

MR. OTT: You mean you should support some type of auction mechanism?

MS. FERNANDEZ: At least a residual auction, is what I have heard; that there should at least be a residual auction. But in terms of for existing -- what are perceived to be existing rights, that the choice of an allocation or an auction should be left up to the region?

(Panel nods affirmatively.)

MS. FERNANDEZ: There seems to be a consensus on that.

One area --

MR. KELLY: Just to maybe clarify that point, if people are agreeing to regional variation on having an allocation versus auction, but in agreement that there ought to be a residual auction, it seems to me that relates to Mark's question about load growth, because if there is capacity that some party thinks they have bought and paid for load growth, is that automatically auctioned off?

I'd just like to understand how the panel understand that issue in what seems to be some agreements.

MS. FERNANDEZ: Any comments?

MR. OTT: I think the recognition that an auction has to be available to parties or customers to, how should I says, allow them to more flexibly adapt to changing conditions, and whether they do that for projected load growth, or whether they want to convert their allocated right into some kind of other, what I will call more competitive right, I think the whole concept --

When I say a residual auction, I think we say an auction that is not necessarily mandatory; in other words, the concept of if you have an allocated right, in our case, an allocated auction revenue right, you again -- there's a mechanism for you to convert that in the auction process without risk, if you will, to a CRR or FTR, or whatever we call it.

MR. KELLY: I may not have asked the question very clearly. Let me try to do it in terms of an example.

If I'm a municipality and I have paid my local investor-owned utility to build a transmission line for me with a capacity of a thousand megawatts -- I'm using 500 now, and I expect to grow into it in the future.

One interpretation could be that I have to auction off the 500 not used. The other interpretation is there is a residual auction mechanism where I may, if I choose, auction off what I'm not using.

And that's the distinction I was trying to get to.

MR. OTT: I'll just finish quickly. I think the concept of auctioning off unused capability is fundamental. You need to be able to auction off and no withhold that capability.

But if you're saying the 500 exists this year, but five years from now, the 500 will be utilized by the load growth, well, obviously then if you have a long-term allocation process, whether that allocation is auction revenue rights or CRRs directly, it will recognize that that excess gets used up over time, because there is a targeted use of it.

But in the interim, you can have it auctioned off. I think that's the -- I see head nods, but I think that's what we were agreeing to.

MR. KELLY: So if I were such a municipality, I wouldn't -- as you explained it, I wouldn't worry that by auctioning off my unused rights, I'm losing them forever?

MR. OTT: Right.

MR. LaPLANTE: I think you'd have to address that in the allocation process. Perhaps they could be given the auction revenues until they grow into the load growth as part of that.

MR. BAYLESS: In our case, a municipality would be incented to trade or somehow or other to dispose of it, because we have use-or-lose and the theory of the system is, if you're not using your FTOs or the CTRs, the RTO can bundle those together and auction residual ATC, if you will, to allow more use of the transmission system.

MS. FERNANDEZ: One other area that we haven't talked too much about that I was wondering if there should be some principles in the final rule about, is what to do about load pockets.

Is there any specific principle that should be included to ensure customers in the load pockets have protection? Or is that something that would simply sort of fall out by looking at the historical use of the system? I see that John is volunteering.

MR. BEUCHLER: Well, I think comments were made a number of times that the existing system works. I think it kind of works in most places.

It means that there is a means for the system to accommodate existing loads. Whether that's done through existing contractual agreements or something like what New York called the transmission capacity for native load, and that, in fact, was used to address things like the New York City area where it was recognized that there were transmission constraints, but nevertheless there was transmission that was designed and built to get remote generation to the load center.

And so, at least in our case, that was addressed in handling these preexisting agreements. I'm not sure, you know, what other mechanism would be used, other than, again, putting the residual into the auction and having all have the ability to procure that.

MS. FERNANDEZ: It sounds like basically what you did is, you looked at what the existing contract right were for the remote generation?

MR. BEUCHLER: Well, the transmission for native load, so called, was not -- was, in fact, not a contract; it was recognizing, however, that -- ConEd, for example, built transmission, you know, up the Hudson Valley to have access to northern and western generation, and so that's how that was separately allocated for the purpose of -- initially separately thought of for the purpose of initially allocating the transmission, even though that specifically was not an existing contract.

MR. OTT: I think, in and of itself, a load pocket, I guess there's an area where you don't have enough transmission capability to serve the load into that area, so I think that, in and of itself, the CRR allocation auction or whatever cannot solve the load pocket problem.

I think the concept of the load in that load pocket has, again, the right to get allocated those -- what existing rights there are, first, if you will, because they pay for the transmission.

That's consistent with the allocation we've been talking about. But I think that the whole load pocket concern really has to be dealt with beyond just a CRR allocation. You have the market power mitigation, you know.

22

And whether this is a state jurisdiction or a FERC jurisdictional issue, the concept of you have local generators there, you know, who the load may need to lock in a long-term contract to, and how that is actually handled. I think it goes beyond this, I guess.

MR. GRAMLICH: But are there ways? I mean, let's say you're a relatively small wholesale customer and you're in a load pocket, at least you think you are because you're in a region that does not have LMP yet, say, you're in the Midwest, and whatever you know about the power flows on the system tell you that you think that the transition to LMP may make you worse off than you were before.

If you have -- I mean, right now, you have some kind of contract, and maybe it's some kind of bundled generation and transmission contract. What would be some kind of equity principle to preserve essentially what they have today, so that in the transition process, they don't lose it? Is it getting CRRs for the transmission part, but essentially getting the unbundled generation part into a separate contract?

MR. OTT: I think that's the concept. Today they have a bundled service, which says they may be served 20 percent by remote generation, and 80 percent by local, so the ability to be able to convert that and not only get the CRR for the 20 percent or whatever it is, but also have the ability to lock in a generation contract for the other 80 or some way to facilitate that, I think that's really the solution to their problem. It's not just a transmission issue.

MR. LaPLANTE: Actually, in New England, we have the small municipals within the Boston area that have this exact problem. They were given additional rights over the interfaces to reflect generation contracts that they had purchased, so that's the way it was addressed.

But I would like to emphasize that you can't make the congestion disappear, and if you are within a load pocket, by definition, the costs are likely to go up.

You should receive all the benefits for all the transmission that you helped support to get generation into the load pocket, but you can't make the impact of the locational pricing disappear.

MR. HEINTZ: I think, first of all, repeating that if the FTRs are following the load and it's based on the historical use, I also think that your question went a little deeper. It's almost, should we identify bundled -- the FTRs associated with each bundled contract, so parties understand that when they were to unbundle or to change, what their rights would be, and I would agree, because, otherwise, you're just going to have a continuation that each one of these bundled contracts expires in whatever year. And then you have a fight over what the rights would be.

MS. FERNANDEZ: Any other questions? We only have a short time left.

MR. O'NEILL: This is maybe minor, but I think, Alan, you said that there were tax consequences to the round trip trading? Now, I think that Dave has -- for muni's, right?

Now, Dave has the same set of muni's who are going to do these types of trades, and did any of your muni's see tax consequences?

MR. LaPLANTE: Not that I'm aware of.

MR. O'NEILL: How come some muni's see tax consequences and others don't?

MR. HEINTZ: I think the issue is that when the revenues -- if, for example, you receive a million dollars worth of CRRs, and you go ahead and you buy at auction, a million dollars, that million dollars is not coming from a member coop, for example. They have tax consequences, or from cities, and as a result, that's revenue that has to be counted as non-member revenue or whatever the tax term is.

And the issue is what you've done is, you have an increased cost; that is what you pay for the CRRs, and you have revenue, which is what you get back. And what you've done is created revenues and costs, and the way the IRS approaches those is looking at the revenues. There's not a netting that's done, and that's the issue.

It's an issue as to whether the dollars are large enough, such that it gives any one individual a tax consequence.

MR. O'NEILL: But my problem is that you see it in SeTrans, yet the muni's in PJM and New England don't seem to have a problem with it, and we both operate under the IRS rules.

MR. OTT: We give them net billing in PJM, so essentially they see --

MR. O'NEILL: So if SeTrans just sent a net bill, no problem? I mean, would that solve that problem?

MR. HEINTZ: I'm not a tax attorney, but whether a net bill would actually qualify or not, would be a question for the IRS.

MS. FERNANDEZ: Were there any sort of one last questions? Any last questions?

MR. KELLY: I could ask one of Mr. Bayless. We were talking earlier about regional flexibility in the allocation process, but maybe standardizing products.

And I think what I was hearing is that New York, New England, PJM, and maybe the Midwest ISO would benefit from standardized products. And you said, well, in the West, you don't need the same products as the East, but what about the Northwest?

Would you need the same products as the rest of the West to facilitate trades?

MR. BAYLESS: I think we believe there needs to be a large amount of standardization within the West, and we're working on that with the other proposed an existing ISOs, and the extreme to where we need to be as far as a common LMP pricing and commonness on the actual products, we haven't quite arrived there yet, but I think we need them to be pretty similar.

MS. FERNANDEZ: I think Udi has one last question.

MR. HELMAN: Yes, one last question for Andy Ott, sharing your PJM experience with us. One of the main concerns around the country has been the properties of the obligation point-to-point right. And I know that in PJM you have had a lot of experience with that.

Could you quickly share with us, examples of cases where utilities rejected a point-to-point right and then regretted it, and then, conversely, a case where somebody accepted it and then regretted it?

And then, finally, could you just talk about learning in the FTR auction and reasons why the auction volume has been increasing over the past few years and the nature of using counterflow FTRs and other features of the FTR obligation right?

MR. OTT: I think we have had -- I don't know of any anecdotal experience from a stakeholder where someone took an obligation right and regretted it because it became a wild negative or a huge negative. There was a concern at one point where a customer did have an obligation right in a negative direction, but they were able to offset that negative by scheduling the energy, which is the positive, so that the net is zero.

So, essentially we have had customers, though, that I have talked to, who took a right and then regretted taking it.

The market rules allow them to surrender that right. In other words, they can come in, and subject to a feasibility test, they can surrender that right back. That's the current rule. So in that case, they were able to surrender the right. It was feasible, meaning it was not generating counterflow that would cause the system to be infeasible.

I forget your third -- I'm sorry.

MR. HELMAN: Just about learning and the people learning to use the FTR auction or the increase in volume.

MR. OTT: I think what you saw, in the beginning again, in 1998, April '98 through April of '99, essentially we had just the allocation. There was no auction. And the system was underutilized. We had 13 percent of the congestion charges collected were excess.

In '99 when we put the auction in, one percent of the congestion revenues collected were excess because people bought those up.

In the early stages, you essentially could buy a transmission right for a dollar and it would be worth $25 in the congestion accounting. So obviously in the very beginning, people were just learning how to use the auction. But very quickly what you saw was a convergence of those auction prices to be consistent with what the long-term congestion patterns were as people used and learned them.

I think the other thing that people learned to do was to bid counterflow FTRs into the auction, because they would say if you pay me up front to take on the FTR, I'll risk, you know, and that promoted liquidity, because then people who really needed the hedge, you know, because they were hedging a monthly product, were able to get that.

So I think the process of evolution where people learned that this thing could be something for everyone. There were some people who wanted to take on, you know, get paid to take on the risk. So it was happening. Those kinds of things happen outside the market, as Dick had alluded to. People will see, quote, "insurance" outside the market, if you will, for a hedge. But it also facilitated it happening within the market.

So what it did was allow people to actually see what the going rate of that kind of hedge would be, so it's sort of price discovery. I'll stop there.

MS. FERNANDEZ: With that, I'd like to thank the panelists, and we'll take a short break and come back at 11:30 with the next one.

(Recess.)

MS. FERNANDEZ: If we could get started. Actually last time we started from the right. Let's start from the left. And as I said, this time there's three minutes for opening statements.

We did, I think as some of you saw, we were over trying to write some of the basic principles that we heard from the first panel that I think we're going to be getting back to. But if you'd all start out, and we gave you the opportunity for an opening statement, and I'll start with Mr. Wickham.

MR. WICKHAM: Good morning, and thank you for the opportunity to be here. We suspected you were going to start in reverse this time. So not unexpected.

I think we need to agree on defining the principles. And first of all, Energy East is a utility that operates -- it has a number of companies, including New York Gas, Central Maine Power, Connecticut Natural Gas and Rochester Gas and Electric. So we are very active in the Northeast in all three ISOs. So we've got some experience in all three ISOs.

But I think from our perspective, there's at least four principles that are needed for a good design:

Efficient price signals;

A system that effects more competition and creates liquid markets;

Cost allocation to follow cost causation; and

A system that honors existing commitments.

And I think there is a number of fundamentals that we think go with that, and I won't go through all of them. But flexibility should exist for both options and obligations. Of course in New York I think you've heard uses obligations. I don't think we think there's a need to mandate options versus obligations. There's some flexibility there.

Regional flexibility should exist for point-to-point or flowgate.

CRRs should be financially based and not physical rights, and the CRRs should not confer curtailment or scheduling priority.

CRR shortfalls must be dealt with in an equitable manner, which includes an incentive for shorter outages, so that's important.

Of course, having a feasible representation is a key here. That's critical. We think it ought to be auction based in some form or other that an auction system is an important part of the process and should have an auction incorporated in the process.

Grandfathering of contracts is critical, and if we don't address some form of grandfathering, we're going to have difficulty implementing a system.

But what I think most important to us is that flexibility is important, and we've talked a lot about flexibility, but to the extent that we worsen or create new seams, I think that's going to be a significant issue. We need to really reduce the amount of seams that we have today and be more efficient.

So we don't want to really create more seams, nor do I think some of we've got in place is working well and some of it we don't want to I think unwind everything that we've got, because I think that would be a lot of cost that we would need to pass onto consumers.

So that's basically what I think are the principles and what I think are the fundamentals, some of which you have now characterized as principles. But in any case, those are important principles and fundamentals.

Thank you.

MR. SIPE: Thank you, and good morning. I want to thank the Commission for the opportunity to speak on behalf of the Industrial Energy Consumer Group.

The model supported by the IECG is a full auction of the entire transmission system followed by an allocation of the revenues from the auction to load or load-serving entities who actually pay congestion charges. NEPOOL has adopted that type of a system in its SMD filing.

The particular allocation of auction revenues in NEPOOL was a negotiated compromise, and while I think it has advantages for consumers and it's fair, it's not necessarily the only reasonable way to go.

The key to any allocation is to come up with a system that returns the value of the transmission system as directly as possible to the load to support the system through their rates. Consumers were the lead advocates of the auction in New England for four reasons:

One is to maximize liquidity.

Two is to maximize the value return to ratepayers.

Three is to maximize market efficiency.

And four is to avoid discrimination and market manipulation.

By putting the entire system capacity up for auction, the largest number of possible trades and reconfigurations are enabled at each juncture. Thinly traded residual auctions are illiquid because the products traded are so limited as to severely restrict degrees of freedom for creating value.

A viable forward and secondary market demands liquidity, and consumers need a forward market in order to hedge LMP volatility. An auction maximizes value because it doesn't take existing CRRs and sell them in the literal sense. Rather, an auction creates CRRs by choosing the set of simultaneously feasible bids for use of the transmission system that maximizes the value.

In an auction, the highest total bids define CRRs that are awarded. This maximizes revenues return to ratepayers from the auction, and in a properly functioning market, should exceed the values ratepayers receive from direct allocation of CRRs. This is because allocating CRRs directly, you have to choose a set of CRRs and hand them out before you know whether you've maximized the value.

Thus aside from the value loss to ratepayers in the form of decreased liquidity, a greater potential for gaming a thin market and the potential for having too few CRRs available at any price to hedge volatility, there is likely to be a direct diminution in the value received by consumers because the CRRs awarded through an allocation are not first maximized for value.

Is it possible to game an option? Yes. It's easier to game a thin one, though, than a full auction, particularly where in a residual auction you can withhold product. It's always easier to game an entitlement than an auction.

On a final point, I'd just like to point out that an auction and an allocation of auction revenue rights gives to consumers the financial equivalent of an option. Because in an auction, where all you're getting back is the revenues, if your CRR entitlement has a positive value, you get that money. If it has a negative value, you don't have to pay. Therefore, an auction and a return of auction revenue rights is a risk-free way of allocating the system which gives consumers the financial equivalent of an option.

And I'll talk about the other two points that I didn't get to in response to questions. Thank you very much.

MR. SINGH: Good morning. I'm Harry Singh with PG&E National Energy Group, the Merchant Energy subsidiary of PG&E Corp. I appreciate the opportunity to be here today.

We have had experience in a bunch of CRR-related markets in ERCOT, New York, California, and to a lesser extent, PJM. Let me start by saying that the SMD NOPR deserves a lot of credit for extending the types of instruments beyond the basic point of point-to-point obligations to include other instruments like auctions and flowgates. This has been very welcome with the traders that I've talked to.

A key question is how prescriptive should SMD be on the details of CRRs? Clearly, too little detail defeats the purpose of having a standard in the first place. But on the other hand, too much detail or being overly prescriptive in areas which remain to be tested, like options and flowgates, or in areas where there's clear regional differences, is also undesirable.

So SMD really needs to strike the right balance in giving flexibility where it's appropriate and ensuring standardization where it's required.

So let me give a few examples. If you take the threshold issue of should you have CRRs or should you allocate CRRs directly to load, clearly many participants would like to see auctions perhaps even at the outset. But they also recognize the political and practical challenges in making such an abrupt change.

So if people can get more comfortable with SMD and LMP using a transition period, I think that would be a reasonable approach. And that's clearly an area where regional flexibility would be welcome.

At the same time, it would I think be useful to have -- to specify the length of the transition period. And this would start no later than the implementation date of SMD, let's say September 2004. So any delays in implementation would then correspondingly eat into the length of the transition period.

Now if you have an auction either at the outset or after the transition period, you face the question of what do you do with the auction revenues. Once again, there's more than one right answer.

Presumably, the principle is to give deserving use to those who are paying the embedding costs of the transmission system. This principle can be satisfied either by giving the revenues directly to load or giving them to transmission owners that can in turn reduce access charges, which then achieves pretty much the same effect.

However, if your principle is slightly different, perhaps to minimize cost shifts as you go to an LMP regime, perhaps even in places where there is a more abrupt transition, then maybe other mechanisms can be used like auction revenue rights, which would more closely mimic the exposure of a load-serving entity to congestion charges.

Are there examples where you should be more prescriptive? I think clearly there are some. One of them would be the financial nature of CRRs and its inconsistency with things like scheduling priority or linking CRRs to resource adequacy.

There's a whole bunch of other questions that should be addressed, but I'm going to stop here as I'm running out of time, and hope to discuss them more in the discussion.

Thank you.

MR. POPE: Thank you. I'm Jim Pope, and I'm here from California to help you.

(Laughter.)

MR. POPE: We have lived life in the petri dish, and it is congested. And I want to take the vantage point from CRRs with respect to the consumer's vantage point, being a municipal utility in a huge load pocket called

Silicon Valley.

And I think that with the work that the staff has done on the 600 pages in the NOPR is outstanding work and a good shot at trying to deal with the issues across the country.

What I would like to suggest today is that California and the West are somewhat different. We need CRRs to provide better access to electric markets, better reliability for consumers, and better cost certainty for consumers and investors.

California has worked in the workshop process, identified about 20 areas where CRRs needed some improvements and had some concerns. Our major six points are that CRRs should:

Strongly emphasize a planning process for transmission;

A common scheduling timeliness or deal with seams issues;

Address regional capacity adequacy requirements;

Market rules should facilitate bilateral contracts;

Rules should accommodate separate control areas; and

Consumers should have or load-serving entities should have priority.

The West, as compared to -- I have a comparison to PJM. The density within the West is about one-fifth of the density of generation and one-fifth the density of high voltage transmission, the West versus PJM's territory.

A lot of lessons that PJM and processes that PJM have done are good lessons learned. The state of California imports roughly 20 to 25 percent because our generation is so far from load.

The bottom line for consumers is that CRRs are really no substitute for infrastructure investment. They're not a substitute for the inadequate capacity, transmission capacity that we've been living with for the last ten years, and I'm concerned somewhat about the kind of punitive nature, meaning that we're allocating the shortage over the people who were still there. Needs to be more of an incentive based. And that the CRRs need to be incenting investment in transmission to solve the congestion problem going forward.

Lastly, I would like to see a pilot somewhere other than our petri dish in California or the West where the density of transmission and generation is not as dense as it might be in PJM or the East.

Thanks.

MR. OSBORNE: Good morning. I'm Richard Osborne with Continental Cooperative Services, which is an alliance of two generation and transmission cooperatives, one operating in PJM and the other in Illinois.

First I would like to thank the Commission for holding this conference and point out that Continental fully supports the goal of the proposed standard market design to reduce the cost of electricity to end use consumers.

I'd like to concentrate the few minutes I have on three areas that Continental as a small load-serving entity may be able to furnish first-hand information that few others can.

Continental supports the continuation of the FTR or future CRR process allocation methodology similar that is currently in place in PJM. However, even the PJM process can result in FTR shortfalls because of insufficient transmission.

Let me give you one example of our congestion costs in PJM. In September and October of this year, which are considered to be shorter months, Continental's member, Allegheny Electric Cooperative, experienced approximately $2.3 million charges in congestion cost. This is in addition to the total wires charge, if you'd care to characterize it that way, and ancillary services charges of about $2.8 million in those same two months. Fortunately, we had FTRs to offset those $2.3 million of congestion charges.

Consequently, Continental recommends the development of adequate transmission infrastructure. Otherwise, we believe that the load-serving entities and consumers will see increased costs.

We also support the regional state advisory committee involvement in the planning and the building process.

We believe that LSEs should receive the CRRs to cover all of their loads and future load growth in an initial and ongoing direct allocation methodology. If there are insufficient CRRs to cover specific transmission paths to meet the requests, then there should be an allocation proportional process on a monthly, not an annual basis, for peak loads for all the LSEs serving over that path.

The monthly peak of the previous year-long period could be used in determining the CRR allocations for each month of the upcoming year. An LSE like Continental's member in Pennsylvania and New Jersey, because it's winter peaking in a summer peaking area, may not get the full benefit of the CRR allocation if it is based on the simultaneous feasibility tests that uses the summer peak as one of the limiting criteria in determining how many CRRs are awarded.

Continental also opposes the use of the auction, except for I should say residual auction process. We believe that the auction process will unnecessarily complicate the allocation of CRRs.

Included in those complications could be the question of adequate credit for a small LSE to bid possibly a huge amount to ensure winning the CRR.

In summary, two major recommendations: LSEs pay all the transmission costs and should receive sufficient CRRs to cover their load plus load growth. And as I said before, the adequate transmission we believe is important prior to the start of the implementation.

Thank you for the opportunity to make these comments.

MR. NAUMANN: Good morning. I'm Steve Naumann from Commonwealth Edison, one of the Exelon companies. I'm here on behalf EEI and both EEI and ComEd thank you for allowing us to be here and present a few remarks.

I looked back to last February and say, boy, have we made progress. We're no longer talking about "if". We're now talking about how to implement a transition, and I applaud the Commission for all its done in what may seem like a long time but was really a very, very short time.

I'd like to talk about some basics. CRRs are pure financial. I think that that debate is over and done with. There are a couple of things in the NOPR that bring that into question. I think those have to be dealt with.

Being pure financial is going to make a lot of the issues we're going to talk about easier.

We believe there is a need for an existing allocation to keep existing firm users, including network and native load, who pay for the access charge, with the same quality of service that they have now. After all, we're talking about a transition.

We do need a transition to an auction, but there are lots of differences. You need some time to understand the patterns and the prices. I think that was talked about. Different areas, different regions have different starting points. Whether you're already, like the type pools in the East already have had auctions -- I'm sorry -- have had allocation, understand how the FTRs work or whatever the acronym is, and are able to price, and retail access also affects when you're going to move to the auction because there are other processes that need to be in place.

There are some state issues. The Commission needs to work with the states that have a buy-in because this does affect the ultimate price to retail customers.

Another bedrock principle is the CRRs or when you go to auction, the ARRs, follow the load. That means again the entity that's responsible for the congestion, if they move to another supplier, they need to get the same rights they had. It's a very easy principle to state, but there are lots of details that have to be worked out.

The one big thing is the provider of last resort's utility cannot be caught in a price squeeze where a customer comes back without the CRRs and now the utility is responsible for the congestion.

As far as regional variations, I think a lot was said this morning. There have to be some basics. But there are other issues: Options, flowgates can change. Differences in retail access programs of individual states.

So thank you very much, and look forward to an interesting discussion.

MR. BITTLE: I'm Ricky Bittle with Arkansas Electric Cooperative Corporation. I probably have a little bit different view of some of these things.

When you think about what we're talking about as far as the CRRs are concerned, it's really -- you've got to step back just a little bit and look at what's going on. Really LMP is pricing transmission at its free market cost.

And so you've got two things. You've got a direct allocation where the customers are paying the fixed cost, plus you've got what now is a free market cost of transmission. So in effect, the customers, depending on how the CRRs wind up, may be paying two different ways, paying much more than the transmission is actually worth.

So I believe that what we're talking about is a cost shifting issue. And when we first started this whole process, one of the first things that came up was stranded costs. I tend to view this unhedged cost of LMP as the same way generators view stranded costs -- that it is a cost-shifting issue and it's one that has to be dealt with in a transition period.

Now thinking of it in terms of a transition period, the first thing is I agree with everybody that said that the CRRs should be assigned a load. If they are paying the fixed cost, then they ought to get some benefit for having done so.

The next thing I think is that during a transition period, the difference between the -- well, it's the actual dispatch cost. I think that that cost should be uplifted as needed to hedge the load that received an assigned CRR. And the reason I say that is, I don't think that there will be enough CRRs in all locations to actually cover the cost that's going to be assigned to those people through the actual LMP process.

And what I'm talking about is only those customers that did not receive a full allocation of CRRs as they would normally serve their load would benefit from that uplift.

The transition period I think should be enough to allow for a complete planning and construction cycle so that those individuals that will be being hit with those increased costs have time to actually do something to reduce those LMP costs.

The last position I think that I would take is that I don't think that there ought to be an auction of CRRs as long as the assumptions that are necessary for full competition to exist are absent. And I think everyone knows where those are.

But the one that really is there is that the current limited nature of the transmission is such that it allows generators to actually influence price rather than being price takers. And so for those reasons, I think that I would have a problem with an auction in the current environment.

Thank you.

MR. GRAMLICH: Well, since you just raised the auction issue, it's interesting that Donald Sipe for the industrials sort of explained why this issue even ever got on the map, which is customers arguing that this would provide better access for them.

Now we have I guess two co-ops, Continental and Arkansas, saying that actually as wholesale customers you think the effect would be the reverse. I just wonder if you could each comment on what the other said to figure out whether there's any kind of common customer perspective on that issue.

MR. BITTLE: I think from my perspective it has to do with whether the assumptions for full competition are in place. If you could assure me that those were in place, then I'd say yes, an auction is okay.

But you can't assure me of that because it doesn't exist currently. And I think that's probably where the difference is, whether you take a realistic view of what we are doing today as opposed to what things would be under a full free market system.

MR. SIPE: I'm not sure there's going to be a common customer perspective. I think, though, that the reason we believe the auction works is that the best consumer protection is a competitive market.

And someone that I really respect came up to New England recently and gave a speech to my group and told us that it's the market, stupid. It's not about carving it up between who gets this and who gets that, but it's whether the market will work.

It's going to be a self-fulfilling prophecy if we start out this process which is not a competitive market by saying let's wait a little while and see if the competitive market will come.

Now there's all sorts of good reasons to have a transition to a competitive market, but there's a difference between delay and transition.

What I think happens with an auction is that you maximize the value of the system and you also maximize your ability to solve your political problems, and let's face it, these are political problems about who gets protected, who gets congestion protection in a system where we know by definition there aren't going to be CRRs to cover all load, otherwise they'd have no value.

So it's a given that LMP is going to create those difficulties. You maximize your ability to handle those political problems by auctioning off and allocating revenues. And the reason you do that is because you do not interfere with the market when you allocate revenues from the auction. You interfere with the market and transactions in the market when you allocate the financial value of the system to particular people and allow them to hold it.

You can solve all your allocation problems on a region by region basis when you're allocating revenues from an auction, and it will not interfere with the proper functioning of a market. You could give the ARRs to charity, and the market would still value the transmission system correctly, and load would still be allowed to hedge and be allowed to have someone who can quote them a firm price.

So I think the advantage to consumers is particularly in the market manipulation area, you can have all sorts of political regional solutions to who gets the ARRs, how you solve your particular problems, how you divvy up the AARs between people with rights that have to be prorated down. You can do all of that, not create a seam and not create a problem for the market, which is really what's going to protect consumers.

MR. POPE: Let me take a shot at -- markets work on supply and demand, Economics 101. One of the other fundamentals is that there's a substitute for the customer or the consumer so they can find a substitute. Unfortunately, the only substitute for electricity seems to be darkness, and that's not a good substitute.

And the markets work in many of the areas where they're working now because they have supply surpluses or supply sufficiency. When you have shortages, there's winners and losers in markets, and supply and demand will find the winners and find the losers.

So we have to consider that. And I believe that's why one of the principles in the first panel of allowing the regions to develop on their own pace. In the West, we have significant shortages. We have long distances between generation and load. We have land use issues on the peninsula and in San Francisco the peninsula as an example where power plants are not welcomed, so the options there are pretty limited. So you can't just take the options you might theoretically solve the problem with because they're not realistically there.

So I clearly support the first panel's letting regions evolve this process in their own way. Thank you.

MR. SINGH: I just wanted to comment on Ricky's skepticism with auctions because of generators being able to set price.

If we're talking about the FTR auction or CRR auction, then certainly generators are just the same as anybody else. They don't have any greater influence. But if the concern is the underlying energy market, there's plenty of other parts of SMD that would address market mitigation there. So I think we shouldn't link these two issues.

In general, I think auctions offer a lot of advantages, some of which have been mentioned. Steve talked about load shift or perhaps I should say load switching, and CRRs following load. I think there again if you had auctions, there are better solutions.

Because if CRRs, which are purely financial and are not linked to physical load, if you say they should shift, then there's always these troublesome questions. What if the new load-serving entity sells it off to somebody else and then when the load shifts back, do you force that entity to buy it back? It's a very difficult issue to address.

But on the other hand, if you are saying it's the ARR that follows the load, which is something that's linked to physical load and it's not completely financial, I think you can address the issue much easier.

So I think I would certainly hope that we look at having auctions, if not at the outset but within a reasonable timeframe.

MR. OSBOURNE: To follow up on, Robb, the question you asked about Continental's cooperative working in PJM, I think our concern is more for certainty of hedging that congestion, and we believe that there is going to continue to be congestion.

We've worked about two years on this, trying to understand how the FTR credits would work, and haven't developed a real comfortable position on tracking and predicting. And I guess there's an uncertainty in an auction process, and our opposition to the primary auction for getting CRRs to the load, and, as I said, not a residual auction. I believe there's a part for that.

It's just that uncertainty of how can the load-serving entity make sure that it gets that CRR to hedge its congestion, and if it is through an auction process, how are those revenues returned? There's a lot of uncertainty and a lot of things we don't understand there. Certainly, a transition period is needed.

MR. NAUMANN: It may be surprising that a representative of the IOUs would want to answer a question about customers, but, in fact, I think you'll find that even in states where there's retail access, the IOUs are the largest customers who are going to be taking service from the RTOs or ITPs.

A lot of the IOUs who have not operated in PJM, New York, and New England, are looking at something that they really don't have experience with. They can learn. Obviously there was a learning curve in the pools, but understanding the patterns, understanding which CRRs become important, and understanding the pricing is going to take some transition period.

And to dump everything into an auction, a mandatory auction right away -- and that's what I understand the option is -- is something that will make it very, very difficult to leave those entities -- and by that I mean the IOUs, retail suppliers, and end use customers that are in regions that are just starting to develop this -- in a similar position than they were before you change, they do need some time for transition and to understand the system.

We also talk to our customers. That's an important thing for a supplier to do, and speaking from a ComEd perspective, trying to work with our customers as we transition into PJM, this is one of the questions that has come up. What's going to happen with congestion?

And when I'm able to tell them that when you start in PJM, just like us as a load-serving entity, you're going to get an allocation of the FTRs, based on your usage now, that, I can't say I've got a 100-percent happy customer, because they're probably a little nervous like we all are.

That really lowers the tension level, and it gives them the answer that they're going to be okay. They're not going to see all of a sudden, these great other costs that they haven't counted on. And that's why you need some sort of transition period, both from a learning perspective for everybody, for us IOUs and the individual customer and the retail supplier.

MR. POPE: Just form the petri-dish vantage point where we rushed into restructuring in California in 1996, and we did everybody all at the same time. We should learn from that, just what Mr. Naumann is talking about and others.

That's a lot to phase in. Let the customer get educated, let the process get educated. I think PJM learned from that. They had a learning process. They implemented markets after they had been piloted. They just didn't build the software and say you have to do it that way.

MR. WICKHAM: I think most of what I was going to say has already been said now, but I think there are a couple of important facts here. One is that we need to start slowly with an auction process. If we start too quickly with an auction process and go too long-term and have the first auction be a ten-year auction or a 15-year auction, I think we're going to get results that are going to be very troublesome. So I think we need to make this transition --

Auctions are important and critical, but we really need to make sure that people get some experience with them, and we don't get committed to too long of a term on the first auctions, anyway.

And I guess the second point is, we've heard some comments about retail access programs and TCCs or CRRs or FTRs, whatever you want to call them, following the load. And I think that's okay, as long as we have the flexibility to financially follow it.

Because if we're trying to physically follow the TCCs, it becomes administratively a nightmare, particularly with retail access programs with customers switching from one supplier to another. So, you know, we just need to make sure that we can do it financially and not be obligated to do it physically.

MS. FERNANDEZ: When you're saying "financially," I know I had some conversations over the break with people from New York, and is that what you're talking about, where it basically goes as a credit to the access charge?

MR. WICKHAM: Yes, that's one way of doing it. I think there are probably other ways, but that's how it's done in New York.

MS. FERNANDEZ: But that one seems like it follows it, but it doesn't require sort of a change in who has the auction revenue rights or the rights; it's just that the money flows through the transmission charge as credit.

MR. WICKHAM: And that's what's working in New York.

MR. SNIPE: I want to be clear when I'm talking about an auction. I do believe there needs to be a transition. We're not talking about a slash cut to an auction, but, you know, Robb asked earlier on, what should the final rule say? The final rule ought to say an auction is where we're going.

Now, I think that there are signs in PJM that with experience, the values of ARRs and the value of those CRRs do converge. I mean, there is actual experience in a pool, and I think that's rather telling, and you would expect that in a market.

But when I said there's a difference between delay and transition, I think we ought to immediately begin to transition to an auction by starting the auction process, allowing that price discovery process to start. I don't think there's much value in just starting with all allocation and doing nothing about the auction in the first year and thinking that somehow that's going to get people familiar.

I think you've got to put these things up to auction, early on, small amounts of the system perhaps at first, for very short periods of time. We recommended in NEPOOL, a very short auction to begin with, so that they are properly valued, but that you need to begin that transition to get to the final rule.

MR. GRAMLICH: Actually, on that point, before we move on, there was a point I noticed in the SeTrans, the zero cost-benefit analysis for the Southeast, that suggested on this issue that it's not all or nothing. Are you saying that perhaps there could be a ten-percent auction to start out, 20 percent, move on and grow it from there?

MR. SNIPE: I think that the way the Commission gets to what the final rule ought to be, has got to be a political process as well as just a purely economic process. It's got to allow people to feel comfortable getting there.

But I think the Commission has to keep its eye on the ball and say this is where we're going, and this is where we are, and that's what the final rule ought to say.

MR. KELLY: Mr. Snipe, just a quick followup on that: I was listening carefully and in your opening remarks you seemed to be arguing just the opposite, that if you have a thinly-traded auction for a small amount, it's subject to gaming, and it will be illiquid and it will be a generally bad experience; don't go there.

But I now understand you to say that as a transition mechanism, it's appropriate; is that correct?

MR. SNIPE: Thinly-traded auction will not get you there. If all you have is a residual auction, you will never get the benefits of a full auction. That's just a matter of economics. You can't get the full value of the transmission system, but as a way of transitioning, because even if you put all of the system up in the first round, I think you'd still probably have a bad auction unless you had some experience.

You'd have people under-value or not know what to value. So it's what type of a bad system do you want before you can get to the one you want?

Now, I think regions ought to be allowed flexibility. In NEPOOL, we're going to go full out the first time we have market trials. That's one way to do it, and the Commission, I don't think, should step in and mandate that if a region has opted to go that way, that if they want to do it in a slash/cut, they can go, but the circumstances in New England are quite different.

We do have experience with congestion. We have already gone to central dispatch. We've done a lot of things that a lot of other places in the country haven't.

And how you get to the end result you want, until you're at the end result, you're going to be sub-optimal, I think. But which sub-optimal you choose has got to be a matter, I think, for the Commission to look at judiciously, because there are just political realities out there; you can't just flash-cut.

MS. FERNANDEZ: Mr. Bittle has been waiting.

MR. BITTLE: Just one other thing: When you start talking about the CRR revenues, buying those at auction, in effect, allows some people to be able to buy the right to enhance their revenue return by maximizing the return from the CRRs and their own generation.

And if that generation can be used in a way to create congestion, then they do enhance their revenue beyond what that ought to be. And that's part of the reason the residual is not going to provide as much value, is because it is the piece of the system that's left and available that's not as likely to create additional congestion.

MR. POPE: Just one thought: I think maybe what Donald is saying is that just residual auctions won't work by themselves, but if you allow bilateral contracts and allow load-serving entities to basically fill their load, and make the auction market smaller, it will be more effective than having a broader based, having everything up for auction, every month, every year.

So there is no confusion, as long as there is bilateral contract availability along with the auction, then the market is covered.

MS. FERNANDEZ: I think Dave had a question.

MR. MEAD: Yes, I'd like to address the issue of scheduling priority for CRRs. Mr. Singh and Mr. Wickham, I believe, spoke about that in their opening remarks.

The SMD NOPR proposed that if the RTO or the ITP ever got to the point where it ran out of bids and there was still congestion, then how do you ration the capacity? It proposed allocating the capacity first to those who held CRRs.

Both of you seemed to dislike that idea, and I wonder if you could just elaborate on it a little bit. What harm do you think comes from giving that scheduling priority to CRR holders, and, secondly, if you're not going to allocate the scarce capacity based on CRRs, what other method would you use at that point when you've run out of bids to allocate the scarce capacity and why would that be better? If I could hear from either or both of you, and then anybody else who wants to speak to the issue.

MR. SINGH: The only reason I *bridge 15 and 16* California when the implemented FTRs, which are not the same thing as we are talking about in CRRs, but still they're a good example. They had this feature.

It was my impression that it hardly ever got used, but then talking to someone last week, I learned that actually it did get used quite a bit. And now going forward, if we go away from the world of auctions to allocating the rights to incumbents, to load-serving entities, and then we say that, okay, if there's outcomes where there's not enough bids, then you get priority over everyone else.

I think that makes people nervous. It sort of sounds like, you know, the world as it's been in the past. And there is -- I mean, I can't prove it, but you could say that is it possible that just by having this rule, you're going to increase the probability of ending up in those situation when there's not enough bids? Some people think so, and, I think, you know, you can look at empirical evidence in California.

MR. O'NEILL: If you don't allocate based on CRRs, how would you propose allocating when you run out of bids?

MR. SINGH: There could be a pro rata allocation; there could be other mechanisms.

MR. O'NEILL: Pro rata has to be based on something. What's it based on?

MR. SINGH: Based on your schedules.

MR. O'NEILL: Schedules?

MR. SINGH: I mean, the only reason you have -- I mean, what do we have today? We have TLR, which is kind of a variant on pro rata.

MR. O'NEILL: SMD doesn't require everybody to have a schedule.

MR. SINGH: Yeah, but congestion, as it occurs, is really a function of the schedules that have been submitted, if you're talking the day-ahead market. And this feature, as I understood it --

MR. O'NEILL: If you have an SMD market without any schedules, nobody has to submit schedules.

MR. SINGH: I do understand that, but isn't scheduling priority only limited to the day-ahead market, not to -- the way I read it was that this goes to the way congestion management will occur in the day-ahead market, and that's really a function of all the sales schedules that come in, all the bids and offers that come in.

And if there is scarcity in transmission, then you've got to decide, you know, who gets to stay on and who gets to go off. So, maybe pro rata would be the only alternative.

MR. O'NEILL: But that would then force you to schedule in order to get yourself in line for a pro rata allocation, and there's no forced scheduling in this process.

MR. SINGH: Right, and certainly you could think of incentives then to over-schedule, but that's not without consequences, since it's a financially binding market.

MS. FERNANDEZ: Mr. Naumann and then Mr. Snipe.

MR. NAUMANN: I agree with a lot of what Harry said. I think the problem here is that we're dealing with a complete congestion management system.

To me, the CRRs are like a negotiable instrument, and I think that's how they have to be viewed. It's basically pay the bearer the congestion revenues under these conditions. If you start putting physical pieces into that, you now, as Harry said, you're going to get a lot of people that are going to say that if you do that, it's not just money; it's affecting my operations, and I can't live with an initial allocation.

The people who don't have rights now are likely to say that I cannot live with an initial allocation, because these things have other value. You run risks on withholding. As someone who can show the scars of three years or so of Midwest debates on congestion management, you start coming up with various rules to fix each possible eventuality.

You have use-it-or-lose-it and you have issues as to whether someone can horde, and whether someone who has a CRR and now has a TLR priority, actually is better off. I really think these things have to be viewed like a piece of paper, and then let the system work, and if, in real-time, you lose controllability or run out of controllability, you don't get a price response, then you do have to go to command and control.

But if things are done right, if the RTO does its planning right, if everything is done right, you should not have those events happening very often. They really should be very, very, very unusual, if you're getting a bid-based market and people to dispatch.

Yeah, it will happen if you get at tornado taking down eight lines in the middle of a system, but, you know, we accept those consequences. So, in that respect, I absolutely agree with Harry.

MR. O'NEILL: What about solar storms?

MR. NAUMANN: It messed up the compass in my car, and, yes, if it takes out -- if it trips relays up north, and trips transformers for 15 lines, you may have a short period of time until you get something back, but, I mean, those things are beyond any kind of reasonable planning criteria.

MR. O'NEILL: But you do have -- we hope that those events where you have to actually implement physical curtailments are very frequent -- infrequent.

(Laughter.)

MR. O'NEILL: Is that going to be in the transcript?

MS. FERNANDEZ: We wouldn't edit it.

MR. O'NEILL: But the question is, Steve, you didn't give us the curtailment plan, and that's what we're looking for. I mean, we were looking for a way to find a scheme to do the curtailments, and that's what we chose.

But, you know, you have to give us a alternative if you don't want us to tie the curtailments to the CRRs.

MR. NAUMANN: You do the curtailments in real time, based first on price and then command and control, because then you know what the --

MR. O'NEILL: What's the command and control scheme?

MR. NAUMANN: The command and control scheme can be easily -- I shouldn't say easily; nothing is easy these days -- you know, if I was the one who chose it, I would say pro rata, to the effect on the constrained element.

I'm sure there are better minds than I at NERC and NAESB, that may come up with some thing that's more complicated than that, and maybe more equitable, but I think that that's fairly equitable.

The other thing that I think everyone needs to understand is, in the real world, you may have a CRR from Point A to Point B, but you're not really supplying from Point A to Point B. And now you're getting into a very difficult -- I'm going to curtail one megawatt from this supplier here and a -- well, let's not get into fractions --

and two megawatts over here, because I don't have an exact one-to-one match with the CRR and the actual point of injection and point of withdrawal.

If it's all financial, a lot of that stuff goes away. And so you can use the command and control, you know, send it to NAESB, send it NERC, to say come up with something that's very equitable, pass it before the Commission, so that we avoid some of the -- we don't have the controversy that there was when Policy Nine first went in service, because there wasn't -- not that it was a bad policy, but there wasn't buy-in a head of time, and get it to work. And I think you'll get a much more workable system than trying to do this as to who has this -- you know, show me your piece of paper, and exactly what you had and keeping track of points of receipts, points of delivery.

MR. O'NEILL: Did you say that we should have NERC do equity?

MR. NAUMANN: Well, you should have NERC do engineering.

MR. O'NEILL: Oh, okay.

MR. KELLY: Let me --

MR. NAUMANN: I'm in a crossfire here.

MR. KELLY: You are.

(Laughter.)

MR. KELLY: See, you convinced me 20 minutes ago when you told the story about customers who are nervous. And when you assured them that they would get CRRs that covered a hundred percent of their historical needs, that gave them great comfort.

What you're saying now, I think, is that to cover those, as you say, rare occasions when demand may exceed the transmission capacity, price-sensitive demand, so that price can't ration the demand, customers could then fear that there will be occasions -- they may fear a lot of occasions when people would come in with, let's say, four times bids to use the capacity that exceeds by four times, the amount of capacity available.

And then if there's an allocation, each of their CRRs gets served to only one quarter of what their promised deliverability was.

While that's a rare event and it's a scenario unlikely to play out, but it's enough to scare people and take away that comfort I think that they'll get 100 percent of their needs met.

MR. NAUMANN: Kevin, I guess I'm a little confused.

MR. KELLY: It's probably me, Steve.

MR. NAUMANN: Well, I mean, what I view -- there are two instances. The first is how you do an initial allocation, and I have confidence in the engineers that I've worked with and we're meeting new engineers in PJM, and I'm learning to have confidence in them, that people have not drastically oversold the system.

Today if an end-use customer has got firm service like they've always had and the system is not falling apart, there may be some hidden redispatch costs that go on now.

But putting those aside, they would get CRRs in an allocation based on that present use. That should be okay.

Now if you get into this tornado or solar magnetic disturbance, I don't know about 12 years ago we had a tornado go through the Chicago area and it took out six 345 lines and we had to drop load temporarily. I don't feel bad about that. I mean, I feel bad that we had to drop load, but when a tornado takes out six lines, you do what you have to. You put the system back together and everyone accepts that's an act of nature.

Nothing, whether you have some physical nature to the CRRs --

MR. KELLY: Let me interrupt, because I think I agree with you. Suppose no lines go down. It's simply the case that you've got an interface that can carry 100 megawatts. Two people each have CRRs for 50 megawatts. But ten people show up bidding to use 50 megawatts each, and they're all price insensitive. None of them will back down their bids in response to price. That's the scenario the NOPR was trying to deal with.

The NOPR says that in that case, the two parties that have the 50 megawatt CRRs get to use it -- no lines down, now. And what I understood you to propose as an alternative and Mr. Singh was you'd take all the aggregate bids for whatever the arithmetic was, 1,000 megawatts, and allocate the 100-megawatt capacity pro rata to all of those, so that the entity that has a 50-megawatt CRR only gets 5 megawatts of service. My arithmetic may not be exactly right on that.

But there are no lines down in the situation I'm thinking of. It's simply how you allocate capacity when price can't allocate capacity.

MR. NAUMANN: Yes. I just find that --

MR. KELLY: Unusual and rare.

MR. NAUMANN: Yeah.

MR. KELLY: That's why I started my question with being persuaded by your story about the comfort people could get from knowing not only that they'll get the CRRs but they can use them, that they won't in effect be taken away by this rare and unusual process that could occur.

MR. NAUMANN: I guess I have to go to what the experience has been in the areas that have implemented LMP and FTRs. One, that we haven't seen that kind of behavior, and you may have wonder why you would see that kind of behavior, and there may have to -- the market monitor may have to step in if there's something being done here.

But I just find this, you know, at this point, if you have to have a rule, then I think the region needs to look at that rule, and it needs, you know, it needs to be very, very finely defined and not broadly defined.

MR. KELLY: But at least it's worth saying we've clarified two situations. One is we proposed a rule that at least in my mind deals exclusively with -- not when lines go down, but simply capacity is oversubscribed and price can't ration for some hypothetical reason. It may never happen. But what's the decision rule if it does?

And the question is whether if our rule is the CRR holders get it, you've raised I think an additional issue of, all right, if that's the rule for that case, what's the rule for when lines go down? Is it something pro rata there, or something else?

MS. FERNANDEZ: Mr. Bittle has been waiting patiently.

MR. BITTLE: I think one thing that you've got to remember is, when you start really endowing the CRRs with physical attributes, you are in effect giving them an additional optionality, something that is worth something, and thereby you have created something else that has to be taken into account when they're sold.

And it also makes them of more value since it's a limited commodity to start with. Somebody that intends to optimize their use of the system of their revenue from it in two different ways, one of them being the transmission system itself, and their own generation, as an additional way of being able to optimize that.

So you have to really be careful when you start endowing these with physical attributes.

MR. O'NEILL: Can I make a request? The people that don't like the CRRs as a basis for allocation when the market doesn't clear, tell us how we should allocate when the market doesn't clear.

MS. FERNANDEZ: I think we're going to try and move on to another line of questioning. I think Mark had a question.

MR. HEGERLE: Yes. Mr. Osborne raised an issue a bit ago in his opening comments. He said essentially that your congestion costs were, at least in a two-month period were coming perilously close to the other access type charges that you were paying for that period. And you noted that we needed infrastructure to make all of this work.

I know in PJM we've seen an increase in congestion costs. Does the fact that we're not seeing a market response in terms of getting the needed infrastructure in place call into question whether LMP and CRRs are actually accomplishing what we kind of hoped that they would accomplish?

MR. OSBORNE: I'll try to answer that question. I guess my impression is is that -- and a comment was directed toward there's my perception. And our perception is there's been a lull in getting transmission lines, except for -- and I'm speaking PJM and certain sections of PJM.

There has been transmission built to connect generators. But, you know, on a relative basis, not much what I would call hardcore transmission lines that can help that transfer capability into some areas. And I think it's a lull.

I don't know as I can tell you why the lull has occurred. Maybe it's uncertainty. I certainly can't say that it's because of the LMP system or FTRs or anything else like that.

The point that I guess the experience point that we can bring to it is not to flash cut into something in areas that don't have LMP or a standard market design right away when you know you have a shortage, you know, and the engineers can tell you that, you have a shortage of transmission. Because it will just create problems.

I think it would be much more reasonable to somehow -- and I don't have the answer to this either -- but to somehow magically, let's get the systems up to some sort of stability and then let the standard market design maintain it.

I'm concerned that if a flash cut into where there are load pockets and a lot of congestion that it will create a lot of problems.

MR. HEGERLE: I was hoping you'd have that answer as to how to get there.

MR. OSBORNE: I could probably come up with one, but I'm sure there would be disagreement.

MS. FERNANDEZ: I guess I was wondering is this something that might almost be like a chicken-and-egg type situation where that once you have an LMP-type system, you'll see what the consequences are of an inadequate transmission, and there's perhaps more incentive to building it.

But if you're talking about getting the baseline very high -- I'm wondering under the current system, you know, people could ask to have transmission built, and a lot of people haven't, is sort of how do you get to the transmission system that you think is what you need or want for competition?

MR. OSBORNE: I guess if I could wave a magic wand, and I think there are lots of technical people certainly in the PJM region that knew probably before LMP was put into place and certainly still now know that if I could build infrastructure where I need to build it to make the system more stable, if they could tell you that. And so if I could wave a magic wand and say let's get things stable, I'd build one here, here and here. And I think there's a technical answer to that.

And then let the market operate.

MS. FERNANDEZ: When you're saying "stable", I mean is that no congestion?

MR. OSBORNE: Not no congestion, but at least a lot less congestion on a continuing basis than some of the areas have now. "Stable" is a relative word. That's the best word I could come up with.

MR. HEGERLE: Are the costs of congestion starting to exceed the costs of building? I'm seeing a yes from Mr. Naumann at least.

MR. OSBORNE: I don't know.

MR. NAUMANN: At the risk of jumping back into a panel last month, I think that's exactly the question you have to ask. Yes, there is congestion. But the costs of building new transmission, there may be easy fixes. I can tell you at ComEd we've done things like retention lines to reduce sag limits and get more throughput. Those can be done.

But what the congestion, what the LMPs are showing and the congestion charges are showing is you're monetizing that congestion so people can compare that to what does it actually cost for these infrastructure fixes? And is this the most economic solution? Or is continuing congestion actually more economic?

I mean, in the end, once you've got the reliability dealt with, and I think we're not talking about the ability to serve load in a reliable manner. I don't think that;s the issue. The issue is the cost of serving that load. And, yes, there's a cost by paying generators, and there's also a cost by building new transmission or load demand response or generator locating within an area.

All those have to be weighed to see which one gives you the net benefit. And if there is a net benefit to reducing congestion, then those who are seeing, you know, gee, it's cheaper to have a line built than it is to continue to pay the congestion charge, should be an easy present value analysis for them to say here, build the line. Reduce my congestion charges. I'll be happy. You'll be happy, and everything will be fine. I know it's never obviously that easy.

But just because they're congestion costs doesn't mean they're bad.

MR. HEGERLE: Right. I don't think anybody's advocating overbuilding the system so that there's not one hour of congestion.

MR. NAUMANN: But it needs to have a benchmark against the alternative. And the alternative is infrastructure, which has a cost.

MR. HEGERLE: Right.

MR. NAUMANN: And the LMP -- these congestion costs allow you to compare building this line, let's say a line -- which could be several hundred million dollar investment, direct investment, to what the congestion costs are to the customers. And then you can do the economic analysis and see if those who are paying the congestion costs believe in the economics. Do they believe in the economics enough to fund the line. And that's why I said I didn't want to fall over or fall back into last month.

MR. HEGERLE: We can talk about who "they" are and customers and all that stuff.

MS. FERNANDEZ: Why don't we just go down the line?

MR. POPE: I don't know which point to take. There's a lot of them here. Again, California, we've got the poster child for congestion called Path 15. We've had several outages in the last several years that were caused by that. And in California, it's about a billion dollars an hour when we have an outage. So economic loss.

That has not incented Path 15 to be built yet. I'm not sure that congestion CRR price signals will in fact incent construction of fixing them, whether you build generation because land use issues may not allow you to, whether you build transmission, because then you've solved the congestion and then the value of the congestion to somebody on either side of it goes away.

And you'd have to look at it from a bigger issue that the process of congestion or CRRs have got to incent fixing the system. Department of Energy put out a report that outlined many congested areas in the country. We all know where they are. I'd support -- I can't remember exactly who said it -- that solve a number of those known congestion paths while you're going through the process in your region to get your CRR and your auction, but let's do both together.

And I think the concern of overbuilding the transmission line ought to be discounted.

I believe, like I think my ratios point out that PJM is working because they have somewhat of a surplus of transmission and somewhat of a surplus of generation or their generation is close to their load center, so transmission isn't a factor solve it.

So I really think we ought to look beyond just the market learnings from PJM. We ought to look at the physical learnings from PJM and allow the regions to address those. And I think FERC has been supportive of getting transmission built.

We've had some state and local siting and all the other regulatory political issues that deal with that. But what we've tried to do -- I'm a member of the Grid Solutions Committee on the Secretary of Energy's Advisory Board. Betsy Moeller chaired that Grid Solutions proposal that it basically says, FERC, please step up and help this country get those congestion paths solved for markets to work and that we have national security for reliability of energy in the country.

And I really think there's enough stuff around to deal with that and writings. And I think the CRRs and your process here ought to amplify and enhance that approach that's already been taken around more physical stuff.

MR. HEGERLE: But you said that the CRRs themselves would be the wrong incentives to get that done. What would be the right incentive to getting something like that done?

MR. POPE: I really that larger cost-benefit analysis of -- and I think the Northwest has proposed a cost-benefit approach that looks at the total benefit for the economics in the region.

MR. HEGERLE: Far beyond the cost.

MS. FERNANDEZ: I mean, is this --

MR. POPE: Far beyond just the microcosm of CRRs and energy products, because what -- again, life in the petri dish, we had physical congestion, physical constraints. We also had constraints due to economics of the overbidding, underbidding, withholding, not withholding, but in most cases, every place you had a slight surplus, market won't work.

So I think you ought to kind of move towards supply and demand, a little more supply meets demand, and prices stay cost-certain.

The other piece in here is the investors need revenue certainty, as customers need cost certainty. If you're going to incent investment, you also have to recognize the revenue certainty to pay for the capital that's going to be brought to the investment.

And CRRs need to -- or the whole SMD process. I don't want to just put it on CRRs. But SMD, LMP, and CRRs need to recognize cost certainty for consumers and revenue certainty for investors.

And then you will start to get some fixes, whether they be generation or transmission.

MR. HEGERLE: Thank you. Mr. Singh?

MS. FERNANDEZ: Can we start doing this fairly quickly? I would like to sort of wrap up the panel.

MR. SINGH: The main argument I heard as to why CRRs aren't good enough is that when you build a line, they're not really worth anything, but surely it's not as simple as that.

I would go to the load-serving entity that Richard was talking about, and say, okay, you're going to see a lower LMP, so you should fund my investment. The only catch there is that if you have a backstop that socializes all the costs and rolls them in, then that LSC is gong to say, well, maybe I don't want to fund your investment; I should wait for the backstop to kick in.

So I know this is an issue from the last panel, but that's really it.

MR. HEGERLE: Okay.

MR. SNIPE: I'll be really brief. I just want to address your first question. I don't think that consumers expect, at least, that LMP is ever going to get transmission built by itself.

We think there are a lot of reasons to do LMP, at least some consumers do, other don't, but there a lot of benefits that you get out of LMP. Simply to address the fact that when people don't want to build transmission, who should pay for the decision not to build?

So I think there are reasons to do it, but the Commission shouldn't just look at LMP. And I'm not sure that it ever did look at LMP, as if the sole purpose was just to get transmission built. I think there's a lot of other moving pieces, including a lot of NIMBY stuff that goes on that is going to have to be addressed in separate forums and in other ways.

MR. HEGERLE: Mr. Bittle, did you have something?

MR. WICKHAM: Yes, again, I think that everything has been said. I think we've gotten off the topic a little bit of CRRs, but, you know, if the issue here is whether CRRs are adequate to get transmission built, I think the answer to that is I don't think so. I think we've got to come up with other solutions, whether it's different return or whether it's some form of allocation of LDMP savings or some other way. I think people have got to come up with a way. I don't think CRR revenues alone are going to incent transmission.

MR. HEGERLE: Thank you.

MR. BITTLE: I agree with that. One of the things that is there with LMP is if you're in an area that's got a high price, basically it's because the transmission is most likely weak in that area. And the reason it's weak is, there's most likely been a tradeoff between the generation that was built and the transmission that was built.

And so, in effect, what you've got is a sudden cost shift from what was a shared cost over a large region, to suddenly it's being priced at a very small region. And so anytime you look at it like that, it's going to be extremely difficult to get both sets of consumers to be able to pay for something that's going to solve a problem that has been caused like that. And so it is going to be difficult, but just the very fact that you put a new transmission system in there, suddenly changes the cost that is there, and there is a cost shift that has occurred, and so somebody's going to be losing revenue, and so in a real free market, you've got somebody that's going to be opposing that.

MS. FERNANDEZ: I mean, wouldn't you be -- it seems that in your example that, to the extent you could lock in some of the generation under long-term contracts within the load pocket.

MR. BITTLE: Well, usually the load or the generation that's going to be that close or in a weak area, is not going to be your low-cost generation.

MS. FERNANDEZ: But you probably had that situation before.

MR. BITTLE: That's true; it is. It does exist today, but if you think about the way those costs are recovered today, they are recovered from the entire load control area. All customers within the load control area are bearing the cost of that re-dispatch that's necessary in order to serve that load.

Under LMP, all of a sudden, because of the way their transmission is priced, it's being priced to a much fewer number of customers, and so that pricing is magnified.

MS. FERNANDEZ: We have a few minutes left, now that we sort of moved the board so that we can actually read what we wrote. In our first panel, we tried to end with talking about some general principles.

There seemed to be a lot of sentiment for allowing a lot of regional flexibility in how the actual implementation would be done, but perhaps coming up with some general principles that could be included in a final rule.

And in terms of what we heard in the first panel, there seemed to be a lot of sentiment for allowing an allocation, not requiring a mandatory auction, but also recognizing that you do need to have some auctions, at least for the residual amounts; that one of the important general principles is that you should not diminish current rights.

I think there's also some discussion that the process shouldn't -- I mean, you should be trying to maintain the current rights, rather than increasing once also; that the rights that are awarded must be simultaneously feasible; that there should be some standard product definitions, and in saying that there could be different products and the regions could decide which products they wanted to offer, so that not -- some regions might want to rely primarily on auctions; other mights might want to rely primarily on obligations, but at least there would be a standard definition of what an option and what an obligation would be.

The sixth was because when we tried to write it out in the terms of the right should follow the load, it got fairly complicated, but that in essence, that the allocation of the rights should not serve as a barrier to entry, so that if customers want to change suppliers, they shouldn't be able to maintain their protection.

And that also there seemed to be a recognition that there needed to be something -- some incentives for encouraging the conversion of existing contracts, perhaps the physical rights contracts to the system.

I guess what we'd like to talk about in the last few minutes is sort of your reaction, if those are the principles, if there are other ones we should add. I mean, in this particular panel, we had a lot of discussion that these rights should be purely financial and take away the physical aspects.

I guess I'd like to give the parties a chance to comment on those; if you agree with those basic principles, think other ones should be added?

MR. NAUMANN: I think those are good principles. I'm not sure if this is a new principle or adding on to No. 6, but where you're looking in a retail access state and you're having the rights in some manner follow the load, I think that there, again, as I said in the introduction, there needs to be a recognition that the provider of last resort cannot be caught in a price squeeze.

I guess it's easy to pick on Enron at its first anniversary, but assuming Enron had been the retail supplier in an open access state, you know, sold off its CRRs in the secondary market, and, you know, then went out of business. The load comes back to the provider of last resort, who now doesn't have anything.

So, I think, at least as a corollary, yes, the allocation should not serve as a barrier, but neither should the processes disadvantage those who are the providers of last resort for those customers. The process itself needs to be designed, taking that into account.

MR. O'NEILL: Steve, can I ask you a question? I mean, what would you have us do? Would you say that you just couldn't sell the CRRs or you had to get the load's permission to sell the CRRs, so that it knew full well what was happening?

MR. NAUMANN: That is, in an allocation scenario -- and I think Harry alluded to this -- it is a much harder question to answer. If you're dealing with ARRs, it's just money. And so they just have to come back with the money.

I know that one of the ways to do it when you're dealing with allocation, is to keep the allocation periods short-term. That at least minimizes that risk.

It may be that -- one idea I've heard is that the CRRs are kind of held in trust by the RTO for the customer, and then in that respect, they can then be returned if the customer comes back.

There's work to be done on that, but I'm saying that as a principle, it's something I think is important not to forget, so that those who have that requirement to serve all takers, don't get caught in a squeeze during the transition.

MS. FERNANDEZ: Mr. Bittle?

MR. BITTLE: I wouldn't want to miss an

opportunity to bring up seams issues. If you look at the fourth one, the set of all rights must be simultaneously feasible, that really can get to a seams issues.

And the way it probably would is the fact that that's going to be done based on a model. And once you are into a model, the assumptions that you make are extremely critical.

And one of the real assumptions that is going to drive the amount of CRRs that are available, is the assumption you make about loop flow. Loop flow is going to diminish the number of CRRs that are available.

And so there are certain of those assumptions that are going to have to be coordinated between regions in order to make sure that they don't create a seam that doesn't need to be there.

MR. POPE: Thank you. I'm going to go back to my six principles, and I think Derrick was in San Francisco and heard the 20 or so issues we had specifically with CRRs.

With respect to your principles, I'd like to -- I'm not sure if they are enhancements or new principles but CRRs and LMP should enhance the transmission planning process, so there's consensus of where things need to ge fixed.

They should have a common scheduling timeline and minimized seams issues. They should enhance regional capacity adequacy and maybe that will minimize the congestion.

Market rules: Bilateral contracts have got to be somewhere in reducing the barrier to entry or the residual auction or some -- the market is bigger than that, so it's got to recognize the broader market.

MS. FERNANDEZ: I guess I'm not following in terms of when you're saying on the bilateral contracts.

MR. POPE: If I'm a load-serving entity, the way I survive the last five years in California is, I have bilateral contracts with delivery certainty to my city gate.

MS. FERNANDEZ: So it this -- so would the principle be something like -- I mean, it seems like in the process -- I mean, it seems like in the process -- I mean, some of your principles really go to sort of a larger standard market design, as opposed to specific transition.

And it seems like what you may be saying on bilateral contracts is that the market design has to be able to support bilateral contracts and allow people who hold those bilateral contracts a way of protecting against congestion costs?

MR. POPE: Yes. I mean, that's the way you -- the market is bigger -- we have a tendency to just focus, and I want to broaden the base. And the rules need to accommodate control areas.

Pooling, joint action, or customers banding together can minimize the leaning on the system. They can self-provide, and then they get cost certainty and customers, that's what they want. They want cost certainty going forward.

And, lastly, I don't know if it's in trust, but my last principle is that consumers should have priority. I don't know if they have an inalienable right to transmission, but the Enron example that Steve used where I've got a bunch of customers that aren't Silicon Valley Power and the muni, but are in the IOU, that are really ripped that their costs went up four cents because their Enron contract went away and now they have to be served by PG&E.

And a lot of that is the cost that they were able to bypass when they were able to go to Enron, but now they have to go back to the default provider. I don't think it's attributed as much to congestion as it is to other political issues in California, but the lesson should be learned there.

MS. FERNANDEZ: Some that sounds like it may be a state retail access program issue.

MR. POPE: It is, but I think the principle -- I don't want to go to that, but I think it's principle about that if the provider of last resort can't effectively deliver when it defaults back to them, then why do you want to be the provider of last resort? I mean, there's no incentive to be there.

MR. O'NEILL: Why do you think you can't deliver?

MR. POPE: Pardon?

MR. O'NEILL: Why do you think he can't? I mean, the price may be very high.

MR. POPE: They can deliver, but it will probably be more costly.

MR. O'NEILL: Right.

MR. POPE: My costs, if you -- my costs as a result of this transmission -- of this transition from where I was to where I'm going, is about 300 percent, I mean, 150 to 300 percent on my transmission costs when it all gets forecast.

And I'm hoping it's less, but I'm going to go up three times what I was a year ago.

MR. O'NEILL: But if you consciously sold your right, and then went back to the provider and the provider said, well, I can't hedge the power transactions anymore, you're just going to pay a higher rate; is there something wrong with that?

MR. POPE: I think, from the consumer standpoint, yes.

MR. O'NEILL: So we should make sure that the consumers like you don't sell the rights and then regret it later?

MR. POPE: I think if the sale is short-term -- I think there was a comment about not making them. The longer the term, the more the risk is.

And some of these are four- or five-year contracts that these large industrial customers had with Enron. And when they went away -- and maybe that's part of the consumers' education, you know, ladder your stuff so you don't have all your eggs in one basket.

But the others -- we're getting into a lot of detail, but I just recognize that the consumer is kind of held hostage if things go upside down and wind up paying the bill.

MS. FERNANDEZ: Mr. Singh?

MR. SINGH: I'm taking service today that I can roll over. I'm still exposed to possible price increases. I'm also exposed to perhaps things like TLRs.

So to give me CRRs forever, I don't think is completely fair. So I would say that if we have an allocation, which is a good idea for a transition, we should also specific a finite transition period. That would be my only addition to 1.

On 2, I would say that --

MS. FERNANDEZ: When you say specify a time period, would that be the length of the contract, or are you suggesting something else?

MR. SINGH: No, if you have an explicit wholesale transmission contract that has a well-defined term of 20 years, sure, that's different; that's the easy one.

But if someone is just taking service under 888 that they renew every year, it's just like an implicit grandfathered contract, I think there it's more difficult to justify that you should give them a CRR forever. Then it's not just keeping them harmless; it's actually making them better.

Besides residual auctions, I think you could also add reconfiguration auctions that are needed. I would hope that we can have a principle that these things should be financial, except perhaps on interties, and if they are financial, we could also add as a corollary, that they should be fully funded, although you could permit variations on how, exactly, we could achieve that.

MR. SIPE: I think the IACG disagrees strongly that as an end state, that an allocation ought to be allowed. I think certainly, as a transitional matter, an allocation ought to be allowed for part of the load, if that's the way to get there.

I think the Commission got it right; I think you guys got it right in the first rule that you issued. You got a transition to an auction. You should stick to your guns.

We don't want to fight this out region-by-region to get the correct result for the market. There's a lot of room to move dollars around under an ARR allocation scheme to make people whole and solve the particular problems. And there ought to be a lot of room for people in particular regions to move those dollars around and a lot of room in a transition to get to the end state.

But the end state has got to be a full functioning and liquid market, or isn't this worth it for consumers.

You've got to get to that stage. And if you want to allow an allocation in the initial stages, that's fine. But the end result should be what the rule currently drafted says it is. You go to an auction.

Finally, there ought to be another principle up there, which is that the rights need to go and to follow load. And I know that's in the rule, but it's got to be up there explicitly I think as well.

I think the ease of getting money to follow load quickly in a competitive market is just another reason why the sooner you get to an auction and you start handing out money, you're going to enable retail access. You're going to get to the market much quicker.

I don't really have a comment on simultaneous feasibility. I don't know how else you'd do it. You have things that are infeasible, I think that sort of answers itself.

I believe that these have to be purely financial instruments. They've got to not have a physical edge attached to them, even for curtailment purposes. And I understand fully that there needs to be some rule for curtailment, and I think it's reasonable to say, if you don't like what we've done, tell us what you need to do. Because it's easy to criticize and it's hard to create.

But a physical curtailment right presupposes some dispatch in the system already, and dispatch just isn't following. In order to allow somebody's transaction not to be cut, you have to presume that there's a transaction there already on the system dispatch just so that you're not cutting.

And dispatch just doesn't follow those rules with financial CRRs. And if you have to make dispatch follow the rules, then you've really slowed down the efficiency of your central dispatch. So there's got to be some other way of curtailing it, and we'll accept the challenge and try to come up with something that's reasonable. But I think they've really got to be financial rights.

Thanks.

MR. WICKHAM: Again, probably echoing a lot that Don said, I think one thing we need to decide is are these the principles for transition or are these the principles for the end state?

Because I think for an end state, we certainly would be a lot more supportive of an auction playing a bigger role than what we've defined here. Here we've defined I think is just a residual auction, and I think we would certainly feel that an auction was more -- had played a bigger role than that.

As far as I think we need to define that it's financial, and that's important. I think one of the things that somebody alluded to, I think Harry in number five where we're talking about the standard definition, it seems to me we need to make sure that we define the quality of the product. That's got to be important. Fully funded or not fully funded, and how do you deal with that? And that to me is important.

The thing I think that still needs to be up there that's not there is we need to come to some way of at least obligating the regions to coordinate with the other regions that they interconnect with so that we don't worsen the seams problem. So we need to come up with some kind of a principle that keeps in place that the seams aren't going to get worse.

That's basically it.

MS. FERNANDEZ: Well, thank you. I think that sounds like -- maybe I think we'll go back and maybe look at some of that over lunch, but it looks like we're getting a little bit late.

We'll start back at 2:15. I'd like to thank the panelists, and see you after lunch.

(Whereupon, at 1:03 p.m. on Tuesday, December 3, 2002, the FERC Technical Conference on Congestion Revenue Rights recessed, to reconvene at 2:15 p.m. the same day.)

AFTERNOON SESSION

(2:15 p.m.)

MS. FERNANDEZ: We're back on. There's one thing I would like to start with. We had sort of a note from the people who were listening in on Capitol Connection. During the morning session, we had a lot of discussions where we got unfortunately into some acronyms.

CRRs are Congestion Revenue Rights. We also talked about ARRs, which are Auction Revenue Rights, which in some areas where the Congestion Revenue Rights or FTRs, whatever they're called in that particular area, are auctioned off. The auction revenues are then given back to load.

So in some of the discussions that we've had it seems like some people were asking what ARRs meant. And that's basically -- when you have an auction system where you're auctioning off all of these rights, it's a methodology for giving the proceeds of the auction back to load.

With that, and it looks like most people are in their seats, why don't we alternate and we'll start down at this end with Mr. Bruggerman?

MR. BRUGGERMAN: Thank you very much. My name is Jim Bruggerman and I'm employed by Williams Energy Marketing & Trading.

Regarding one of the major issues, or the major issue maybe is should there be a mandatory auction? And I think the answer is yes. And I think deferring the decision of an auction or allocation to an ITP is an abdication by the Commission on a matter of market principle.

Regarding the mandatory auction, the sooner the better, even though an immediate auction would be very desirable, I recognize all of the comments and concerns by those that oppose an immediate auction. If there's a transition, it should be as short as possible.

One suggestion would be to have monthly auctions for the first year to give everyone the opportunity to learn the congestion patterns and prices, and then after the end of the first year, start a Phase II where longer-term CRRs such as six-month, one-year and multi-year CRRs would be auctioned.

I won't go back through the all reasons people have given for having a mandatory auction except just to add that it would greatly enhance the secondary market, making it very much more vibrant than it would otherwise be.

Regarding how to allocate CRRs, I agree with the process that's outlined in the NOPR, which is basically cataloging existing firm obligations using designated resources at the time of allocation up to the current peak load and then having to secure rights for load growth.

In regard to how competing entities can acquire CRRs, the new supplier should get a proportionate share of the CRRs held by the previous supplier. In other words, the congestion rights would stay with the load.

Regarding the question of should the Commission allow regional variation on how rights are allocated to load, I agree basically with what Mr. Ott said this morning, and that is the answer is no except for the treatment of grandfathered agreements, and the rest of the allocation process should be standardized to preclude barrier to entry.

That's all I have. Thank you.

MR. DAUPHINAIS: Good afternoon. I'm James Dauphinais of the firm Brubaker & Associates, Inc. or BAI, and I'm speaking on behalf of the Electricity Consumers Resource Council or ELCON.

On behalf of ELCON, I would like to thank the Commission for the opportunity to speak on the transition to and the allocation of congestion revenue rights or CRRs. I would also like to note that my comments today for ELCON are preliminary, and we hope to learn as much as we contribute to today's discussions.

ELCON supports the Commission's move to a standard market design. However, we are concerned that if the market value of the transmission system is separated from end-use customers who ultimately pay for the transmission system, market participants will unduly profit at the expense of consumers.

We are also concerned that if there is not a sufficient amount of CRRs available in the market, end-use customers that are market participating loads or their suppliers may not be able to hedge their transactions against congestion and power markets will remain unnecessarily unstable and potentially face future reliability problems.

In regard to the allocation of CRRs, ELCON believes CRRs or the market value of those CRRs should be allocated directly to end use customers based on historic use of the transmission system by their historic supplier. We also believe it would be reasonable for non-retail access utilities to hold in trust CRRs or the value of CRRs that have been allocated to the utilities' end-use customers. We believe this approach would provide a reasonable way to ensure the market value of the transmission system remains with end-use customers when retail choice is made available.

In regard to the issue of ensuring reliable and reasonable stable competitive markets, we believe it is vital that the Commission's transition to an allocation of CRRs support a liquid and transparent forward market for transmission rights that ultimately reaches out to the horizon of new generation and transmission construction.

The forward locational price discovery necessary to provide the lead compensation necessary to make markets stable can only be derived from the forward trading of CRRs to hedge expected LMP charges, not the LMP charges themselves. To ensure reasonably stable markets and that the customers can adequately hedge their LMP congestion charges, a sufficient number of CRRs must be made available to the market by auction or in the secondary markets. This means that ultimately all allocated CRRs must be auctioned, and that the market value of those CRRs must be allocated rather than the CRRs themselves.

It also means that in those regions where a substantial amount of the total CRRs have been allocated and moved to mandatory auctions, in other words, the allocation of the value of CRRs rather than the CRRs themselves, will need to happen sooner rather than later.

Moreover, in such situations an allocation of CRRs rather than the value of CRRs will be an impediment to retail access as it will be difficult for market participating loads or their suppliers to obtain the CRRs required to fully hedge their transactions against LMP charges.

I have a couple of other comments, but I'll pass on them because of the time. And I look forward to your comments.

Thank you.

MS. HAGER: Good afternoon. My name is Janice Hager and I'm manager of Rate Design & Analysis for Duke Power and I'm speaking today on behalf of Duke Energy.

Through Duke Energy North America, our company is a leading developer of merchant generation nationwide with 14,000 megawatts in operation.

Duke Power serves about 18,000 megawatts of retail and wholesale load in North and South Carolina. Therefore, we believe Duke Energy has a unique perspective on the differing views that LSCs and other market participants bring to the issue of CRRs.

To approach the issues of CRRs, teammates from all over Duke Energy came together in a cross-functional team, and the objective of the team was to develop an allocation and auction methodology for CRRs that balances three perspectives that are sometimes not that easy to balance:

The need of customers of load-serving entities, such as bundled retail load, to receive sufficient CRRs for the LSC to be adequately hedged against congestion costs;

The need of marketers and generators to have a deep and liquid market for CRRs so that they can have the opportunity to serve load and hedge congestion; and

The need of state regulators to ensure that customers are not unfairly burdened with unhedged congestion costs under SMD.

I feel like our team was successful in coming up with a set of principles very similar to what has been developed here today. And these principles are:

First, that the allocation of CRRs should not create barriers to customers or LSEs seeking to change suppliers. To accomplish this, the allocation of CRRs must follow the load in the event that a customer elects to change suppliers.

Second, all those who pay the access charge should be allowed to request allocations of the CRRs of their choice, and all parties should have the ability to purchase any CRRs they desire in a full and open auction.

The next three principles that we developed are ones that I think either were implied this morning or were not on the list, and we would like to see them added.

Thirdly, that the method of allocating CRRs should provide incentives for economically sound investment.

Fourth, that the method should facilitate the development of a deep and liquid CRR market to allow all interested parties to participate in the CRR market.

And fifth, that CRRs should have no physical attributes. In other words, CRRs are financial instruments and should not give their holders any scheduling rights over non-CRR holders.

And in order to achieve these principles, we believe a two-step process should be adopted by the Commission.

First, CRRs should be allocated on at least an annual basis to LSCs for their projected peak load. And then allocated CRRs should immediately be made available in an open auction with the revenues going to the entity that was allocated the CRRs.

Duke Energy urges the Commission to adopt the guiding principles it has discussed today and the principles that we will set forth in our comments. And while we will propose a plan which we believe satisfies these principles, we don't believe it's necessary that every RTO adopt the same plan. But we do urge the Commission to evaluate RTOs' proposed plans in the light of these principles.

By using the proposed guiding principles, we believe the Commission can provide a fair and reasonable method for allocating CRRs and address the concerns of state regulators.

I appreciate the opportunity to speak today, and I look forward to opportunities to discuss further the principles that I've set forth.

MR. KELLER: Hi. My name is Jim Keller and I work for Wisconsin Electric Power Company. And I too appreciate the opportunity to be here and share my thoughts with you today.

Wisconsin Electric supports the overall goals of the FERC in establishing its Standard Market Design. The electric consumers will benefit from developing open access regional transmission systems and robust regional electric markets.

Really a key to this is the Congestion Revenue Rights. Wisconsin Electric is an investor-owned utility that serves about half the load in Wisconsin and the Upper Peninsula of Michigan.

Wisconsin Electric is a load-serving entity, but we are also a transmission-dependent utility. As you may know, about two years ago we and other utilities in the area moved our transmission assets into a new transmission-only company, the American Transmission Company.

This makes Wisconsin Electric one of the first in a growing number of formerly vertically integrated utilities that are now transmission-dependent utilities.

The transmission system upon which we are dependent is very congested. We own generation in Wisconsin and the Upper Peninsula of Michigan. We also have significant long-term purchases from sources both within Wisconsin and outside Wisconsin to the south.

The importance of the transmission system therefore is not something we take for granted. Getting CRRs right I think is a key to SMD's success.

I think going forward FERC should establish principles regarding CRRs, and the list from this morning is I think a good start.

The most important of these principles is that existing rights should not be diminished. A load-serving entity should not be forced to purchase in auction the Congestion Revenue Rights associated with serving its load.

I suggest that FERC not require auctions of CRRs. An auction for residual CRRs is appropriate. Customers should be allocated CRRs to match their existing firm transmission service.

Such an allocation should include a provision for load growth. Allocated CRRS should be options and not obligations. And CRRs should travel with the load.

If there is a mandatory auction, the load-serving entities must be allowed to opt out of the auction. The alternative of requiring the load-serving entity to bid the maximum allowed bid for the CRRs at auction, and then receive the revenues, has too many attributes that only increase risk and/or cost. And I can go into those in more detail. That was a bit of the discussion this morning.

Finally, CRR rules should not work to discourage new infrastructure, but rather to encourage it. CRRs must be of a term long enough to match supply options. Otherwise, new generation will not be built nor purchase contracts entered into without delivery price surety.

Thank you, very much.

MR. MESA: Hi, my name is Phil Mesa. I am with the Bonneville Power Administration. We are a large Federal power marketing agency that is currently participating in the development of RTO West.

Before I get into my prepared statement, I do want to recognize--I think where we were going this morning was very beneficial. Going with principles and trying to identify commonality on those principles is a great way to go. I think it helps, or it aids in allowing regional solutions to some of the more technically complex problems that we have got, especially in the Pacific Northwest.

I probably would have added a couple of things on those principles. I would add sort of like an SMD Prime Directive. That should be: To Do No Harm.

The second area directive I would add is: To provide certainty.

Now I think the combination of those two will greatly aid in developing a Standard Market Design that both jurisdictional and nonjurisdictional entities can embrace.

The bottom line, I believe we've got to set up an SMD that can stand on its own merits. End consumers must want to go to an SMD and not be forced to an SMD.

Bonneville would like to further describe some of our primary issues that we will be considering in the development of RTO West as well as pursuing our comments on Standard Market Design.

Risk and complications associated with congestion management systems and the potential for price volatility cost shifts and overall cost increases for consumers is a concern.

Two points with respect to this one.

RTO needs an array of tools to effectively manage congestion in ways that do not shift costs or create price shocks. An example of this I think we touched on earlier is the ability to expand the system when appropriate. RTO West's proposal includes a planning backstop authority to facilitate that.

Second--and I want to add, I am not implying that the RTO West proposal is any less complex than SMD. In fact, the reverse may be true. But I think it is important for us to move forward in a thoughtful, deliberative way.

Long-term uncertainty introduced by SMD in future rulemaking is a concern. That gets to the secondary directive. I think the more certainty we can provide people on what the deal is would be a major help.

I think the problems that FERC has perceived across the country are not perceived to be quite as serious in the Pacific Northwest, and I think there is a perception that we've got fairly healthy bilateral markets.

Pre-existing contract rights protection I think kind of gets to the Prime Directive: Do No Harm. And I will reserve the rest of my comments for later. Hopefully they will come up in questions.

MR. STUART: Hi. I'm Mike Stuart. I'm from Wisconsin Public Power and I'm representing TAPS. TAPS members are TDUs and load-serving entities. Their objective is to provide a delivered price to the customer that's low and predictable. They've invested billions of dollars in generation to achieve that objective.

My Company, WPBI, alone has outstanding a net present value generation investments of approximately two-thirds of a billion dollars. And without long-term transmission rights, those generation investments could not and would not have been made.

And so protecting those investments against congestion charges is extremely important to the TAPS members. TAPS members are perhaps more exposed to congestion than the normal utility because, unlike the vertically integrated utility who has their generation close to their load, there are many TAPS members where that is not true.

That is not because they desired to locate their generation remote from their load, it is a consequence of history. Many of them when they broke into the power industry needed to obtain a backbone baseload resource to be successful and to compete with other suppliers. And in order to do that they had to break away from their incumbent supplier to find that backbone. And in many instances the incumbent supplier was not going to be a partner in losing load.

So we looked to partner to people who were nearby but not in the local control area. And because of that, many of us have our key resources in a different control area and move them across control area borders that are congested.

And because of that, we are over-exposed to congestion charges and our ability to obtain CRRs to protect ourselves in this new regime is critical.

We are dependent upon the assignment of CRRs for price security and to protect the value of our past investment, and also to keep the delivered price to our customers low.

In order to protect our investment, TAPS members have developed two key principles which we recommend to the Commission. The first applies to the existing firm uses of the System, and the principle is that there must be no diminution in the ability of LSEs to utilize existing resources with existing transmission to serve load on a long-term basis.

In order to accomplish that, there are some corollaries. One is that the CRRs must match the existing transmission commitments both in terms of megawatts and in terms of duration.

The second means that the CRRs for today's firm uses should be assigned up to the peak load even if not simultaneously feasible. I think there was some misunderstanding this morning, or perhaps inadvertent loose language.

A simultaneous feasibility study is not a system capability study. It is instead looking at the simultaneous uses of the system to assure that there's revenue adequacy in terms of fully funding the outstanding CRRs.

The uses of the system now, the system is built to accommodate it. We don't have TLR-5 events. So the existing uses can be accommodated. The question is revenue adequacy.

We advocate fully assigning CRRs to all current firm uses and using any revenue excess that flows out of the study that is done, the simultaneous feasibility study, to fund the CRRs.

To the extent that is not sufficient, we think there should be an uplift and that it should go into the transmission revenue requirement so that there's full funding, and there is in fact full protection of existing uses.

The second principle is to protect the LSEs and their ability to finance and commit to the long-term resources in the future. We must have long-term CRRs to provide the certainty that we need to finance long-term investment and build the infrastructure that is going to be necessary for this new system to work.

With that, I will pass and reserve the rest of my comments.

MR. WOLAK: My name is Frank Wolak. I am going to focus my remarks on three points associated with the CRR allocation process. These are summarized in more detail in comments I filed with the Commission on the SMD.

The first comment is: Do not auction off CRRs; allocate them to load-serving entities.

The second comment is: Allow a secondary market for CRRs that could take the form of a formal auction after the initial allocation has taken place, but this would be a voluntary auction.

The second point concerns the initial allocation of CRRs. They should be allocated to load-serving entities net of the sum fraction of local generation that these load-serving entities own where this fraction depends on the extent to which the local generation provides a physical hedge against congestion charges.

So just to highlight the argument behind these points, the first is the reason against auctioning the CRRs is that there are two uses for CRRs.

The first is a passive hedge against locational price differences that market participants cannot impact with their unilateral behavior. Basically, just taking the difference between the prices times the quantity with no ability to influence the price.

The second source of use of the CRRs is as a revenue source for locational price differences that a market participant can influence these locational price differences through how it bids and schedules its resources.

And because most LSEs currently have very little ability to alter their hourly demand for electricity because of essentially no retail pricing programs that face final consumers with hourly price signals, the really only value of CRRs to LSEs, pure LSEs, is their passive congestion hedge value, the first use of CRRs.

However, generators on the other hand have the significant flexibility in how they schedule and bid their units and can adjust, can impact locational prices through how they schedule and bid their units. And for this reason they have a second additional value for CRRs, which is the value associated with essentially congestion revenue generation so to speak.

And for this reason, auctioning CRRs to the highest bidder is likely to lead to a situation where the entity that wins the CRRs is the entity that is able to essentially do the most damage in terms of congestion charges that it causes.

So allocating CRRs to loads initially guards against this. But I think it is important to emphasize that it should allow a secondary market where LSEs can engage in mutually beneficial trades with other LSEs or market participants based on that fact.

Then the last point is just to say that for the same reason that pure generation owners had the incentive and ability to use CRRs as a revenue source, load-serving entities with generation have the same sort of incentive, and for that reason some sort of netting should take place relative to their local generation ownership in the allocation process based on a weighted fraction of load.

MS. FERNANDEZ: Rob.

MR. GRAMLICH: Janice mentioned the--I'll give you warning before I jump in--mentioned the way rights should be allocated.

Let's assume for the moment we're just allocating rights and forget about whether we're allocating revenues or the actual rights, but we're allocating rights.

We heard this morning I thought a difference between New York and PJM on exactly who gets what rights. I thought PJM said they allocated the rights according to the existing uses based on where the historical generators were to serve the historical load, and New York--and maybe people can correct me if I'm wrong, or John Buechler can step up--I guess it was New England, actually, I think Dave LaPlante said it was more pro rata; just everybody gets a pro rata allocation to the system not necessarily based on where people were doing.

MS. FERNANDEZ: I think that's more New England.

MR. GRAMLICH: More New England. Okay.

I think you were advocating the former based on what? How should this be done? I know you commented on it, and other people have commented on exactly who gets what rights. That would be useful.

MS. HAGER: What we're proposing we believe is similar to where PJM is going. I think when Andy was talking this morning he started off talking about where they began. But I believe where they're going--and someone can correct me on this--is to allow those entities that pay the access charge to designate which CRRs they need.

We think this is very important, for example, for a muni or a co-op that is looking to change suppliers, to be able to point to a different set of CRRs so that it can better match its supply to load point-to-point and have the best options, the most flexibility to hedge for congestion.

MR. GRAMLICH: So let's say you're a public power system in Northern Wisconsin and you have a coal plant that was built 20 years ago, Mike, or so and you have a transmission right that you've always used to deliver power from that coal unit.

If you have a contract, then that would be presumably the rights that you would be allocated?

MS. HAGER: Well I think the distinction would be that we are proposing that you would have the right to ask for that CRR, but that you would not automatically be allocated that CRR.

You would have the right to request on an annual basis, at least annually--we could see it being done even every six months--to say for the next six months, for the next year, this is the set of CRRs that I think I need to best hedge congestion.

If I have a long-term contract with a certain plant or a certain system, that is most likely the set of CRRs I am going to be asking for.

MR. GRAMLICH: Let's say you're another load-serving entity in Northern Wisconsin and you also desire the rights to this scarce capacity across the WOMS interface, but you never purchased outside of that interface in the past, you relied on local generation, so you really have no claim, no contractual or implicit claim to the capacity. You can request and be treated the exact same way as the company that has a contract in hand?

MS. HAGER: Right. We believe that is an important principle, that all entities have the same access to the CRRs. They can all request. They can all request the exact same path. They would be allocated on a pro rata basis.

And at that point, I have a choice as an entity that had requested those CRRs. I can choose to purchase other CRRs. I can choose to go it with a different suppliers. I can choose to fund an upgrade. I can--you know, I think there are a lot of options out there, but we believe an important principle so that you're not creating barriers for entities to change suppliers is with that allocation to give everyone equal access to the pool of CRRs.

MS. FERNANDEZ: I saw several cards going up. I think I am going to go with Mr. Keller first. I think you may have said the same thing, or similar.

MR. KELLER: Thanks. Yes, the problem with, Rob, in your example where you had the one wholesale entity with a long-term contract across a congested interface, and then a second one comes along who up to that point hasn't used that interface but now wants to, it would be nice to be able to allow that second entity to use that interface.

But if the first one already has a huge investment--either they built the plant, or I think in your example they have ownership or a long-term contract commitment--you can't very well take that away from them.

Oftentimes the investment in generation is a multiple of the cost of transmission, not that the cost of transmission is minimal; it is very significant, but oftentimes that is actually the smaller component of the overall value of the energy and power that is being brought in.

So I think it is very important to be able to recognize the past commitments that people have made. Don't take that away from them.

There are two reasons for that. One is, people have made commitments to meet their load in the past. The other is they want to be able to make commitments in the future, commitments that will allow new generation to be built, to make investments either directly or through a purchase contract of some type.

That important investment in new infrastructure will not be able to happen unless people can have some surety that they can manage the delivery costs to get that power to their load.

MS. FERNANDEZ: Mr. Dauphinais, also, and then we will go down the line.

MR. DAUPHINAIS: I had a slightly different take, as I guess was previewed in my opening remarks.

We would start with the historic usage, for example in utility nominating various CRRs. But then once that's done, if it is a retail access utility we would suballocate a portion over to the utility to hold in trust for the end-use customers who are still taking bundled service.

And then the other portion would be suballocated directly to end-use customers so that where they go, no matter where they go, they are getting a piece of that CRR.

Now the CRRs are probably not the ones they really want to hedge their transaction, so they're going to have to go into the secondary market or the residual auction to get what they need.

However, this is of course one of the great risks which I also previewed in my comments, is that if they can't find what they need in the secondary market there may be a need to move from an allocation of CRRs to an auction sooner where, instead of getting the actual CRRs, they get the value of those historic CRRs.

MS. FERNANDEZ: In a nonretail access state, how would you do it?

MR. DAUPHINAIS: In a nonretail access state, the entire pile of CRRs would be given to the utility to hold in trust.

There is one important thing I wanted to add, and this especially pertains to load pockets in this whole allocation process.

If the CRRs that are allocated to the utility are based on the aggregate LMP utility system, it is going to be important that under the retail access that the retail loads can take that aggregate LMP as a price. Because they're going to be getting a piece of a CRR that is associated with that aggregate load, not with their specific nodal location.

By the same token, they should have the right to opt out to nodal if they want to do that.

MS. FERNANDEZ: Mr. Stuart?

MR. STUART: Well I think if you're going to allow the CRR assignment and auction process to take away people's transmission rights that they need to deliver past investments to your load, you're going to have chaos.

People have made serious investments. I mean we made a $200 million investment to buy this goal plant, and it took us years of litigation at FERC and almost antitrust litigation to get the transmission which was taken on a hell or high water basis, which means we had to pay for the transmission initially whether the resource was there or not. The plant blows up? We still have to pay for the transmission.

So you now turn around and use this to take that away from us and you're going to have real serious problems. So I don't think that works at all.

The other thing is, if you do this pro rata thing the way that -- based on who is asking for it, you have already got enough market monitor problems out there without creating more.

Somebody in Eastern Wisconsin, there are only a few people I can buy from; there's no firm transmission into the system from the West or from the South. It's physically constrained. And so if you allow the people that are the suppliers there to bid and take away my load, there are only a couple of people I can buy that replacement power from and it's the same people who are taking away transmission from me. I think you have a very serious market power problem if you start going down this road.

MS. FERNANDEZ: Mr. Mesa?

MR. MESA: Well I think based on the discussions I've heard, I think this is a prime example of where regional solutions might be the way to so because I can't think of one single solution that would work all across the country.

I think in different areas you've got different histories and different reasons for having certain solutions work for them. And to try and apply that all across the country would be problematic at best.

I think, going back to the principled approach along regional differences is probably the best way to skin this cat.

MS. FERNANDEZ: Frank?

MR. WOLAK: I just wanted to sort of distinguished between two reasons for increases that load might pay--higher prices load might pay as a result of LMP. I think the initial conditions being that in most cases the load is a full requirements' customer from say an investor-owned utility, so the price that they pay is averaged over a very large geographic area and they're paying the average price.

Then in the movement to the LMP market, we could think of the one extreme is the case of no CRRs and you're simply paying the LMP at your location. The intermediate step is the case of you have CRRs to cover the congestion payments that you're making, even assuming that you're getting full CRRs for all the congestion that you're having to pay to bring distant generation into your local area.

That ignores the--so that is going to cover you for that source of price increase. But the thing that is going to still result in a higher price than you paid under the Full Requirements' solution or the Initial Conditions is the fact that now you are paying the nodal price for all the energy that you consume at your location.

In that sense there isn't enough CRRs to cover that for the simple reason that that is not congestion; that's just the fact of higher locational energy and you're now getting averaged over a different region.

And so I think that in the sort of discussion that was earlier of the Do No Harm, I guess that is one of the issues that is very important in the transition from the existing system to an LMP is these sorts of distributional issues.

MR. BANDERA: I've heard a lot of discussion about the cost shifts as the nodal prices change, and a lot of consumers are concerned that they are going to see higher prices and they want to be hedged against the higher prices that nodal prices will bring.

What about the customers who see now a lower nodal price? Should they have some sort of obligation to somehow they be responsible for helping sort of mitigate the wealth transfer that occurs in nodal prices? Or should they be able to simply benefit while the high cost entities sort of pay more?

Should there be some sort of equity solution maybe to take something from the people who benefit from a lower nodal price potentially?

(Pause.)

MS. FERNANDEZ: If we don't have volunteers, we will draft people.

(Laughter.)

MR. WOLAK: I'll certainly jump in.

I mean, I think Derek raises an excellent point following right on what I said in the sense that if you believe that--if there is a belief that competition is going to lead to lower prices for everyone, then in some sense the pie is getting bigger and it is possible to do exactly what you're saying.

True, the people in the low nodal price area are going to get a lower price; they're just not going to be as low a price as they would get. And the people in the high nodal price area are going to get a lower price, as well.

Then I think the argument there is, yes, that sets the initial conditions. That satisfies the condition of Do No Harm. Then from there, for incremental load the people in the high-cost areas are going to have to pay more for incremental energy in their high-cost area, and the people in the low-cost area are going to have to pay a lower amount for what they pay because of their location in a low-cost area.

So to the extent that you value the fact that you want everybody on the bus for benefits of restructuring, I think that is a very admirable goal.

MR. BANDERA: So would like maybe for instance a counterflow CRR obligation on the consumers that are in a low-price area, in a sense similar to sort of what was discussed maybe in the New England allocation where everyone had pieces to the entire region, maybe if a customer in a low-price area had sort of still an obligation to buy generation at each generator in the region through a negative counterflow CRR, would that be a potential solution to that problem?

MR. WOLAK: That certainly works. If you think of it in terms of allocating initial CRRs, you can allocate the initial CRRs in such a way that essentially everybody pays, if you like, on average the nodal price--the node-weighted quantity price at every node. And then for any incremental or decremental relative to that, they would pay at the nodal price.

So that is certainly I think the equivalent to what you are saying.

MS. FERNANDEZ: Mr. Dauphinais?

MR. WOLAK: So it just all depends on how you allocate the initial CRRs, I think is the way to think about it.

MR. DAUPHINAIS: One of the keys to me is how CRRs are allocated. As long as the CRRs are allocated and have a specification for the delivery point that matches the basis for the pricing, and we were able to do a full allocation of CRRs, there shouldn't be much difficulty.

One caution I would have on all this based on some of Frank's remarks is that we're not going to make load pockets go away with LMP. Load pockets exist because of environmental restrictions, other siting restrictions, or reluctance of incumbents to basically facilitate or allow the construction that is necessary to make these load pockets more competitive. So that is one warning I would add, as well.

MR. HEGERLE: I just wanted to go back to the question before.

Janice, you mentioned in your opening remarks the method of allocation CRRs need to have as incentives for economically sound investment.

When I heard your explanation of it's up in the air every year, what you'll have, if you even get what you have, and Mr. Stuart had a lot of concerns about holding on to what he had, I was trying to figure out where would those incentives come from? Where would there be investor certainty for coming up with capital to build, whether it's generation or transmission, under that kind of scenario?

MS. HAGER: That's a good question. This is an issue that we really, we did struggle with a good bit.

We were really trying to balance some concerns there. I think in a large part, generators and marketers may often feel like because they don't have existing contracts they have a hard time getting new contracts. Therefore, that they don't have to worry about certainty because they have no contracts.

That creating a situation where LSEs have opportunities, there are no barriers to changing suppliers, that provides additional opportunity to generators and marketers that should enable them to get contracts.

Then the issue is who bears the congestion risk. I think that can depend in a great degree on how the contract is structured as to who bears the congestion risk and what the certainty is.

One party could have certainty, or they could split. The generator could have its contract going to a hub, and then the load could pick it up and move it from the hub to its load where you're kind of splitting the uncertainty associated with congestion.

So, you know, I don't deny that the method that we've proposed does not provide price certainty to all parties, but I do think it provides more opportunities for load to change suppliers and therefore gives more opportunity to generators and marketers that should help them to obtain financing.

MR. HEGERLE: What's the short-coming if I'm an LSE and I want to go to an alternate supplier, of me going to the RTO who administers the CRRs and reconfiguring them, whether it's to an auction or directly in some fashion? How would that not work to meet that same need?

MS. HAGER: Well I presume that maybe an element of that is that there are already certain CRRs that have been allocated long-term. Is that sort of a premise of your discussion, that you have already granted certainty to previous holders?

MR. HEGERLE: Right.

MS. HAGER: I think the concern that we have with allowing long-term CRRs to be allocated and not redistributed--to be allocated for long-term and not redistributed on a frequent basis--is that it will just limit to a great degree the pool of CRRs that are available; and that it does create barriers to entry.

MR. HEGERLE: Well what do we do with Mr. Stuart's example, then? I mean there needs to be balance. I see the point about there needs to be liquidity, and people have to be able to access them, but he is not trying to access an alternate resource, he's trying to access a resource that he owns.

How do we help him in that scenario?

MS. HAGER: I guess the question would be: Should there be--and some folks will probably have an answer to this--because I signed a contract earlier than you did, should I have more access, or more certainty, or more, be able to get access to CRRs in a different manner than the next person?

So I guess I don't really have an--I understand the concern, but I think we see it as a tradeoff. And one of the things that we are--one of the attributes we see of our proposal is that it gives LSEs a lot of flexibility from year to year. You can really reconfigure your CRRs through the allocation process annually.

MR. HEGERLE: Yes, Mr. Stuart.

MR. STUART: I guess one person's tradeoff is another person's loss of their key resource.

(Laughter.)

MR. STUART: But the reason we are proposing that people who have existing resources get long-term CRRs to go with them is so you don't spoil past investment decisions. These decisions were made, you know, coldly based on the system that was in place at the time. And if you are changing systems and you don't do some transitional mechanism to protect that investment, you are literally going to leave hundreds of millions of dollars out there stranded.

It is like a de-rate of my baseload unit that I have to go and replace in a load pocket. That makes no sense to me.

In terms of new resources, the reason we're suggesting people be able to get a long-term CRR coupled with their new resources is exactly what was suggested in the question: To provide the certainty. The investment is not going to come if there is not some certainty that goes with the investment.

We are suggesting that we get long-term CRRs so that I don't have to go to my board and say, well, we've got a CRR for a year, but after that I'm not sure what happens. We may have to auction it, and I don't know if the market will value the CRR at that point in a way that is accurate to protect us from congestion.

And I don't want to go to Wall Street and say what is the delivered price of energy? Well, it might be 35 mils the first year, but then it could be 60 depending on what the congestion looks like down the road.

If you are going to incent investment in the system which is necessary to make the SMD work, you are going to have to figure out ways to give the investors some certainty.

Now we are right now building a power plant. The load signal is already getting there. We are building a peaking plant. We're building it at a distribution sub at our largest member where the minimum load is going to exceed the amount of generation that comes out of that unit most times so that we don't have to worry about congestion.

An IPP has a plant that they want to build and sell to me. I am happy to negotiate with that and get the CRRs for the delivery of that plant, and I am happy to work with them on locations in Wisconsin that will allow the delivery in a way that will minimize the risk of congestion. But don't take away my rights, and do give me the certainty that I need to go finance.

MR. HEGERLE: Mr. Mesa?

MR. MESA: The RTO West filing utilities have been tackling this very same issue. The approach that we have taken is to bifurcate transmission rights into catalogue transmission rights, and then financial transmission options.

We protect the existing contract rights' holders. And if there is an unencumbered transmission capacity, those are sold off as FTOs.

We recognize that transmission needs change, and there are incentives put into place. So we are using the carrot not the stick to get transmission capacity off the table from preexisting contract rights that may no longer be needed to serve load and made available for new entrants.

So I think the solution that we are trying to get to is along the lines of the Do No Harm Prime Directive where people will be incented to release those and sell them into a reconfiguration auction.

MR. HEGERLE: If we go with Janice's proposal -- sorry to pick on you -- but do we end up with all power being sold in fairly short-term blocks as a result because you can't get the longer term certainty of knowing?

Because the LSC has choices, but year to year, it doesn't even know if it will get the CRRs to get to your resource even.

MS. HAGER: And I probably should have added another element to the proposal. That is, we're not opposed to long-term CRRs forever, only initially. Only until you begin to get a real handle on the value of CRRs, and then we're perfectly comfortable with moving to long-term CRRs, but just do have a concern about going there initially.

I do think that, yes, you've raised -- you've put in an element of uncertainty until you get to that point, but I think you've also achieved some benefits.

MS. FERNANDEZ: I sort of would like to move to maybe sort of another line of questioning.

(Laughter.)

MS. FERNANDEZ: I'd like to talk with Mr. Stuart about simultaneous feasibility. And I guess what I'd like to ask is in terms of your existing contracts the way you're describing them, are they point-to-point contracts?

MR. STUART: We're taking network service. We have designated network resources.

MS. FERNANDEZ: Okay. So I mean, basically your concern is that you get adequate CRRs for -- I mean, if you got adequate CRRs based on your historical peak, would that be sufficient?

MR. STUART: We're only looking for CRRs up to our peak load, that's right. I think the reason that I touched on the simultaneous feasibility study is there are a number of principles that were put on the board this morning, and they're in conflict with one another if there is not enough infrastructure there.

There is a way -- one of the conflicts I see in the NOPR where there are concepts that create tension is the concept that the existing uses of the system are supposed to be fully protected. That is, you're supposed to get CRRs for them, but the amount of CRRs you make available to the marketplace is done on the basis of a simultaneous feasibility study.

The transmission that was granted was not granted on the basis that all of the uses of the system would be simultaneous. It was granted based upon diversity and other factors that they thought made it realistic to provide to grant the long-term firm request.

A lot of people have been looking at the simultaneous feasibility study as a test of system capability, and I don't think that's what it is. I think what it's actually testing is whether or not you're going to be able to collect enough congestion revenues to fully fund the CRRs that are out there, and the fact that there are uses of the system beyond those that are simultaneously feasible that are being provided today without TLR 5 events indicates that there is additional capability in the system to provide the firm uses.

Therefore, if you do the simultaneous feasibility study and you don't have enough CRRs to go around to everyone, my point is if that's a revenue deficiency problem, let's deal with the revenue deficiency, but let's not deprive people of CRRs for their firm uses, and by doing that you harmonize the two concepts in the NOPR that at least to me were in tension with one another.

MR. O'NEILL: Are you saying that your rights are essentially probablistic or depend on other generators being run or something of that nature?

MR. STUART: I think that there are a number of things that are going on when the firm transmission was granted. I don't think that the suppliers assumed that all uses of the system would be simultaneously. I think Mr. Kelly made that point this morning that people were granting the service request not on everything being done simultaneously, but being done on load flow studies that are based upon historical uses of the system.

They are also assuming that there are counterflows going on in many cases.

MR. O'NEILL: So that your rights are dependent upon some other generators running somewhere in the system?

MR. STUART: It could be counterflows. It could be redispatch. I know there are counterflows. For example, I think that right now on the transmission service requests that have been granted from Minnesota into Wisconsin, I think there are something like 400 megawatts of counterflows that are there.

In many cases those counterflows were granted by -- were arranged by the transmission provider to allow them to sell more transmission probably coincidentally between rate cases, but that's what was done.

MR. O'NEILL: But that would be part of the contract, the transmission contract that you would have, that the person would honor that contract would somehow or another be able to call upon the generator to create those counterflows when you need it?

MR. STUART: I think that that's part of the redispatch of the system to maintain reliability for firm if that counterflow isn't being scheduled at the time I think the transmission provider to curtailment of firm transactions, does go in and redispatch the system.

I think right now a lot of that redispatch is hidden and passed through to retail ratepayers under the bundled system. But in fact that happens to maintain the firm transactions. And they may be doing those redispatches since they can pass them through a retail fuel adjustment clause, there's no expense for them, but they planned on doing that in order to provide me my firm service. Now I shouldn't lose my firm service if the world has changed and they don't want to do what they've been doing in the past.

MR. O'NEILL: Right.

MR. STUART: That's where I'm coming from.

MR. O'NEILL: But if they sold you firm service based on a predicate of running certain generators at certain times, that should continue?

MR. STUART: That's exactly what I'm saying. I'm saying that I shouldn't be deprived of my firm transmission because they decide they want to change the way they --

MR. O'NEILL: Why would that be a problem under the --

MR. STUART: Well, if you do a simultaneous feasibility study, I'm not sure about what assumptions to into that simultaneous feasibility study.

MR. O'NEILL: You would assume that it would include the running of those generators that made the --

MR. STUART: There are people that know more about that model than I do, but it's my understanding that

that model does not take into account redispatch, for example. It just takes in the transmission uses of the system.

MR. O'NEILL: There's nothing that precludes it.

MR. STUART: There's nothing that precludes it. If you do the -- if you change the way you model the study, you change the answer.

My point right now is the way the model is done or the way I understand it's going to be done in the Midwest, we have a very serious concern that when they run the model in that fashion, that not all of the firm uses will be simultaneously feasible.

MR. O'NEILL: You have a problem with how they're going to do it in the Midwest, not the SMD NOPR per se?

MR. STUART: Well, again, it goes back to what you mean by simultaneous feasibility. It looked to me from reading the NOPR that simultaneous feasibility was not system capability. And if you read the PGM rules on what simultaneous feasibility means, they say very explicitly that this is not a system capability study. It's a run that's done for different purposes.

So you can get the right result if you do the simultaneous feasibility study in a different manner. But I think the way that it is being contemplated to be done today is not a system capability study.

MR. O'NEILL: In your comments, could you explain to us how you would like the simultaneous feasibility test to be done in order that you could ensure those rights that you have now?

MR. STUART: We can do that.

MS. FERNANDEZ: Yes. Or if there are other ways of -- I mean, it seems like your basic issue is that you want to ensure the existing rights.

MR. STUART: All I'm saying is if there is capability in the system that's being used today, we shouldn't be deprived of a hedge for continuing to use the system the way we've been using it in the past.

MR. BANDERA: When the transmission owner has given you your firm rights and then it implicitly knows that it's not going to be feasible every hour of the year and is willing to do redispatch during portions of the year, and as you say, providing the counterflow necessary, would it be reasonable then to give or obligate the transmission owners to hold counterflow CRRs that make your firm contract feasible so then it would be simultaneous feasible and just place the obligation on the transmission owner who sold you the firm to provide the counterflow through a counterflow CRR?

MR. STUART: That's obviously one way to address the issue.

MR. DAUPHINAIS: I want to follow up on what Mike has said, because I want to strongly support it. It's an extremely important issue.

Transmission system requests for firm servers when they were evaluated, many of the transmission providers when they evaluated them, looked at what are the likely loadflow conditions? What flows are going to exist because of load being there? Not necessarily which generators, because load was going to be there.

And they made a decision on the likelihood of counterflows being there and issued some firm transmission rights based on the high likelihood of counterflow being there.

We move into this new environment and they apply simultaneous feasibility tests, and there is this attempt, which is somewhat academic, to just look at one system condition and not look at reality or look at the system in the same way they were being looked at when evaluating firm transmission requests.

The key on this initial allocation to get it right is that the simultaneous feasibility test has to be done in the same manner in the region as firm transmission service requests were approved. If you use the same methodology, there should be enough transmission rights out there. We should be able to avoid pro rating rights, unless there's truly double sales of transmission by two transmission providers where there's parallel path. That should be the only exception to the rule.

MS. FERNANDEZ: There may be some instances where I mean we had some discussion this morning about differences. I think particularly in the west there are some issues with load diversity, and some of that may be able to be fixed by a certain seasonality.

MR. DAUPHINAIS: The load diversity is something that was considered in the firm transmission was granted. Again, the likelihood of certain things happening -- and a lot of this is load based, so it's not really affected by the market directly.

Yes, we hope load is going to be responsive to prices, but we know in reality it's not that responsive. It's responsive when prices get real high. But for subtle changes, it isn't.

MR. STUART: There's one other critical issue that I should mention in these studies. When Jim talked about the region, it's very important what you mean by "the region". And right now in our part of the world, the way the RTO borders are configured, doing the simultaneous feasibility -- I'm in the Midwest ISO -- doing it on a Midwest ISO basis, you have to make some pretty critical assumptions about what kind of loopflow you're experiencing from the neighboring RTOs whose facilities are really intermingled.

And so that's one of the key assumptions that goes into the simultaneous feasibility study, and if both entities are not making common assumptions, you may end up with additional problems.

It sounds easy setting up the model, but when you start trying to figure out what the right assumptions are, it gets complex quite quickly.

MR. O'NEILL: What are the neighboring RTOs that you're talking about?

MR. STUART: I'm located in Wisconsin, which is in the MISO. The Illinois companies are in PJM. And the high voltage transmission system, the backbone system where all the loopflow in the area occurs, goes Chicago, Milwaukee, Minneapolis, St. Louis to Chicago. So all of the transactions on that loop are interrelated and the flows are interrelated.

MR. MESA: So actually, this conversation that's just occurred basically describes what had been proposed in the RTO West proposal. But using an approach that was different than CRRs, we had an adequacy test to make sure that the transmission assets were sufficient to cover the preexisting obligations or the CRTs.

And for our unique needs, we've settled on -- we couldn't just use one single feasible dispatch to test that. There's too much variability in hydro operations and other resource operations. So even though we could pin down a peak load, we weren't sure what resources, what dedicated resources would be used to serve that.

So we are envisioning a range of feasible uses in this catalog sufficiency test. And to the extent that a transmission provider had been providing redispatch to support that or could have been through curtailment rights that were not associated with reliability, but under these conditions, you don't have that right to move power.

But anyway, under that catalog sufficiency test, we would identify what congestion management assets were required to make good on those firm obligations. And the RTO could then call upon those congestion management assets in real time if those conditions were to occur.

MR. O'NEILL: Essentially you're describing a call option on a generator if necessary.

MR. MESA: Yes. And we allowed the PTO, or the participating transmission owner, to either provide that resource up front or rely on the redispatch market and basically create a financial obligation.

MR. O'NEILL: I don't see anything in the NOPR that basically prohibits that. As a matter of fact, although it's probably not explicit, I think lots of people use call options to create transmission rights.

MR. MESA: I think the thing that was a little bothersome in the NOPR, though, was it gave the impression that simultaneous feasibility tests would be done basically with a single snapshot. And if you have resource variations, what are you going to assume for that resource operation? You know that anything that you choose is going to be wrong.

MS. FERNANDEZ: I think Dave had a question.

MR. MEAD: Yes. I'd like to follow up on something Frank said in his opening statement. If I understood you correctly, you were concerned about the potential for market power or the exacerbation of market power when an entity is using the CRR for something other than a hedge.

For example, if a generator is located inside a load pocket and it has a CRR into that load pocket, the fact that it has a CRR increases its interest in creating congestion so it can get even more revenues. And similarly, a load that also has some generation rights inside a load pocket would have a similar problem.

And if I understood you correctly, it was your concern about that that led you to conclude that we should not have auctions of CRRs because the options would go the people who valued them the most, and they would put that --

the reason they had that value is because they could use it for market power. And also that just in terms of allocation, you would devise your allocation so you wouldn't allocate those entities too many CRRs so that they'd want to exercise their market power.

But then I was confused because then you said then you would allow a secondary market. And if somebody was interested in acquiring CRRs through an auction to increase their market power, I mean, it would seem to me that that same interest would exist in buying those CRRs in the secondary market.

So is there a reason why you didn't recommend an absolute prohibition on these entities buying or acquiring CRRs?

MR. WOLAK: I've been around Dick a lot, and I guess if you're foolish enough to sell, then I guess you deserve the consequences. But basically the idea is also is that if there is an opportunity for trading, then there can be trade between entities that may find mutually beneficial trades.

But to me, the idea is that, I mean, I guess what I would say sort of following on things that were said earlier today is that I don't think you can escape the allocation problem, and I think the allocation problem is at the heart of the issue, for the simple reason is that if you say I'm going to auction, a mandatory auction, but in the first step you've got to allocate the ARRs. And the ARRs are purely financial instruments. And if you have purely financial CRRs, then the only difference between allocating the ARRs and allocating the CRRs is when you get paid.

With the ARRs, you get paid right up front as soon as the CRRs are sold. With the CRR allocation, you get paid at the end of the day as essentially the revenue stream.

So my view would be is, you know, why do anything different? But to the extent that once you've allocated them, I think retrading for all the reasons that people like markets, and I certainly like markets, is a good thing. But the idea is that you as the load-serving entity can go to other load-serving entities and say let's swap, or let's trade these CRRs. We'd like some of the ones you got. You'd like some of the ones we got.

And so you'd be careful as to who you sell and how much you sell to, because you know the reason that that guy wants to pay you so much money is because he expects that he's going to be able to get sufficient revenues as a result of that. And, you know, you go into it with your eyes open.

So that's why I don't think it's mutually inconsistent what I said, as I said, is that I'm giving you the CRRs. You sell at your own risk.

MR. MEAD: I'd like to hear others, but just to follow up on that for a second, there might be a few loads in a load pocket, and one load foolishly sells its CRRs to a generator. And granted, that load is harmed. But then so again are all the other intelligent LSEs who knew not to sell to that generator.

MR. WOLAK: That's a problem. But I mean, you know, in some sense you hope that you educate everyone so that people will, you know. But I guess what I -- you could say I'm going to prohibit everything, but I would hope that that's sort of not the steady state solution that we want to get to. We want to get to a solution where people understand how the market works and know what they need to know how to do.

And I think the one thing is I think most people will be, in the initial allocation, it's not going to be perfect, but if it sort of respects existing rights, then I think what's going to happen is, is you'll get some secondary market activity. And you can run a formal auction. But as long as it's voluntary for people to buy and sell, I don't think that there will be any problems.

But to me, it's still the issue is fundamentally you've got to figure out allocation. I mean, auctions, even if you made them mandatory, if you've got that initial step of ARR allocation, you're allocating.

MR. MEAD: Mr. Stuart?

MR. STUART: I wanted to comment just briefly on that, the statement that was made at the beginning. I think Mr. Wolak has identified a very important issue, because I think it can be a very significant problem.

I had a somewhat different take on what might be the best solution to that. It struck me, if I understood what he was saying correctly, that if you own generation in the load pocket and also own CRRs into the load pocket, that somehow there would be an accounting and you would lose some of the ARRs into the load pocket.

I think that from a policy standpoint, that would hurt very badly for people who have key resources outside of the load pocket and they're relying on them to serve their load. But I think it might also have the unfortunate implication of disincenting people to build new generation in the load pocket, building generation in the load pocket is going to decrease CRRs into the load pocket, I think you may be creating a disincentive to the real solution to the problem.

I think a better way of dealing with it from my perspective anyway is to take the CRRs and give them to everybody up to their peak load, and then if you've got somebody in a load pocket who has that combination of generation in and CRRs in, I think that that's something that the market monitor should be watching very, very carefully, particularly if that person is acquiring more CRRs in a secondary market or an auction so he's holding more than his peak load because it suggests that he's intending to do something with them.

And I think this is a solution that would be better resolved by the market monitor rather than giving people disincentives to construct generation in the load pocket.

I think it's really a must-run issue. I think the real problem is if the generator in the load pocket isn't bidding in when his marginal costs suggest that he shouldn't be bidding in. So I think it's a withholding problem that I would have the market monitor address.

MR. WOLAK: Can I respond?

MR. MEAD: Could we go down the line first and maybe come back to you? Mr. Keller?

MR. KELLER: I had my little tower up and then I put it down because Mike sort of beat me to the comments I was going to make. I don't think it's reasonable to net the generation against load-serving entities' need for CRRs, they should get their allocation from CRRs up to their peak load.

We've got, I mentioned earlier on that for our specific instance, we are in a load pocket. We have most of our needs met by our own generation, but we've got a significant percentage that we meet through purchases, much of that from out of state, and we don't do that on speculation. That's just to meet our load. And those are just the CRRs that I'm probably the most concerned about. And to net generation against that would make no sense to me.

MR. WOLAK: I guess what I would just say in response is, is that I think everyone is forgetting the fact that you can't give everybody CRRs up to their peak. That's basically physically impossible. But because of the simple fact that there is load located next to the generation, and there is essentially no CRRs for that.

So the idea is there is going to be residual congestion that has to be managed. And the question is, is how do you share that among the market participants? And a simple example is if you've got two LSEs in a given geographic area, each with 100 megawatts and you've got say 100 megawatts of local generation and 100 megawatts of transfer into the area, somebody's got to pay that 100 megawatts for local generation.

You can only sell as many CRRs as you've got transferring into the region. So you've got to decide how you allocate that scarce CRR capacity. And that's the fundamental issue at least that I'm addressing.

MS. FERNANDEZ: I think Kevin had a question.

MR. KELLY: Yes. We've been talking about the initial allocation of CRRs to load and customers. I was wondering if it was appropriate to allocate CRRs to generators, either generally or in some circumstances.

The circumstance that initially comes to mind is where a generator in the past has paid some interconnection and upgrade costs in return for a stream of credits in the future and if the transition takes place before it's fully recovered its investment if CRRs are the appropriate way to handle that.

It might also be for cases where a generator doesn't sell into its region but exports to another region and is considered to be a party that should pay an access fee.

And I thought I might start with Mr. Bruggerman. He's gotten off kind of easy so far.

MR. BRUGGERMAN: If the generator has contracted for the transmission service, I think that it's appropriate for the allocation to be to the generator. Some generators provide full service in that they provide not only power from their generator but also arrange for the transmission service for the customer.

So in those instances, I think it would be appropriate to allocate to the generator.

MR. KELLY: Thank you.

MR. DAUPHINAIS: In the short run, at ELCON, we're hesitant to allow generators and other market participants other than LSEs and end use customers to have CRRs. However, there is a difficult transition issue which was specifically mentioned in regard to generators that under the higher-of policy, may have paid higher than the rate, and/or they may have paid up front, and they are getting transmission -- they're getting credits back through their transmission service.

There needs to be some way of dealing with that. Ultimately, I think that allocation should go to load as load would be paying the access charge. I don't see where the generator should be paying the access charge, going forward, and I'm not sure we would want that, because that still resembles a rate pancake.

But some mechanism probably is needed to deal with the transition for the generator that is out money for investing in their transmission system in advance.

MS. HAGER: I think that after the transitions are over, the only case where a generator would receive CRRs would be for participant funding, participant-funded upgrades.

I think there are a couple of transition issues. One would be the case where you mentioned where a generator has been -- has preserved long-term or even short-term point-to-point that ends after the beginning of SMD.

And in those cases, we're proposing that the holder of that point-to-point transaction be given the choice of continuing to pay an access charge and receive CRRs in return, or to not pay the access charge and receive no CRRs.

So I think we see that as a transition issue, as is the case where generators have funded upgrades and received credits in return, and that's additionally a transition issue.

MR. KELLER: I mentioned in my opening remarks that I thought that customers should be allocated CRRs to match their existing service. By customers, I mean transmission customers, and to the extent that you do have an example where a generator has -- you know, as part of their decision in building a plant, has justified, you know, the business cases to have control of transmission to a hub, for instance, they are transmission customers and they should get as well, initial allocation of CRRs associated with that.

MS. FERNANDEZ: We are getting close to our time, and I would like to see if we can organize be a little bit more high tech in this panel than in the last one.

We'd like to sort of go over some of the general principles we've been trying to ask various panels as to what some of the general principles are.

Sarah, if we could get the PowerPoint projected. It worked.

We tried to type up what we heard from the last panels. And most of it was what was written on the flip chart, and there are a few other ones that we wrote after the first one. We added a few other ones.

And if we could sort of go down these, and if we could -- if people have comments as to which ones they agree or think other ones should be added?

MS. McKINNEY: Do you just want to read through them?

MS. FERNANDEZ: Yes, why don't you go to the second one.

(Pause.)

MS. McKINNEY: Alice, would you like me to just read them very quickly?

MS. FERNANDEZ: Yeah.

MS. McKINNEY: I'll just read this list very quickly: Each RTO should develop a transition process that implements these principles:

The first is allow CRR allocation; require residual auctions; don't diminish current rights; rights must be simultaneously feasible;

Standard product definitions; multiple products may be offered; regions could make choices among products;

Allocation should not serve as a barrier to entry and benefits of rights should follow load.

Incentives for conversion of existing contracts, and purely financial CRRs with procedures for rationing, and then we also talked about some general SMD principles, which included seams coordination between RTOs; the need to assure adequate infrastructure and market design that accommodated bilateral transactions.

MR. GRAMLICH: That list there is incomplete, but it was just that we were trying to separate the CRR allocation issues from general SMD.

MS. FERNANDEZ: Any volunteers? Janice looks like she's the fastest.

MS. HAGER: I think we're in general agreement with that list in terms of a residual auction. I believe our position today, as we stated it, is that we really support a full auction from the beginning, but very importantly, based on an allocation of CRRs where the LSE or the entity that's paying the access charge can select the CRRs it chooses, and receives those revenues back.

Initially, that's a short-term auction, so while we do support an initial full auction that has some important conditions with it, then I think the other --

probably two others that I mentioned in my opening statement that we believe probably should be added to the list would be making sure that the method of allocating CRRs provides incentives for economically sound investment.

It's very important to us that that price signal be there and that it be clear and that costs not be socialized unless there is no other choice.

And then also, we believe it's important that whatever method is used, it facilitates the development of a deep and liquid CRR market that allows all interested parties to participate.

MS. FERNANDEZ: Why don't we just go down and start with Frank and see if you agree with those or want to suggest other ones.

MR. WOLAK: I would just once again reemphasize that the real focus here is on designing an allocation mechanism, because, as I said, if you're going to give out ARR rights at the beginning, then you're essentially allocating CRRs.

I would say just cut out the middleman and just allocate the CRRs. The second would be to make sure that there is a sort of secondary market for people to be able to trade, but it's voluntary trade, supply-and-demand offers from market participants.

The other is to guard against the incentive to use CRRs to essentially cause congestion as a source of revenue for firms that own generation, and in that sense, you know, I think that has some prescriptions about the initial allocation process that I discussed.

And then finally, I think that it's very important to, as I said in the slides, to make the purely financial. I think all of the problems with scheduling priorities, if you wan to hear horror stories, I can tell you many from California on the sort of problems with scheduling priority attached to them, because I think many of the speakers from the previous panel had it exactly right in terms of there is an additional value that it really can create havoc between the physical world and the financial world, and you don't want that havoc.

MR. STUART: It's hard to argue with a number of things you have put on the board, but I would make an observation about those principles. And a number of them are perhaps in conflict, and I point to don't diminish people's uses of the simultaneously feasible and the no barrier to entry.

And I think really the only way to try to rationalize those as all being able to be achieved at the same time is looking at the broader principle of SMD that you need to get the infrastructure adequate.

If we're using LMP to just ration scarcer and scarcer resources, and not fixing the systems so that people have access to the generation market, we're going to fail, and so I would make that observation about these principles.

The full auction principle that Janice suggested, obviously from my initial statement, I disagree with that. I think there should be an allocation.

I think a voluntary auction is fine if it works and we thinks it's valuing the rights properly. We may well go into that market and sell our rights, but I don't want to be forced into that, to bid the maximum to get my right back.

It seems to me that that's a lot of cash flow issues, credit issues, and bureaucratic issues that can be avoided. We might actually auction our rights if we think they are being overvalued by the market.

The other thing that I would point out is that one things that's missing from those principles is the future component. I said at the outset that to induce new investment in generation resources, you need to design the CRR that is longer-term and covers new investments.

And so I think that's one critical thing that is missing. And the other thing is, I think you're going in the right direction by focusing on principles, and I compliment you on asking people what they think the right answer is. But I think there is a procedural component that is pretty critical.

And I think those general principles are a good start, but I don't think that the Commission, in the SMD NOPR, can stop at that level of generality. I think you need to adopt corollaries or something else that puts some meat on the bones in terms of doing those things, what are the objectives, what must be accomplished, so that there is an objective test against which the regions can measure success and in which you can measure success when people bring back things to the regions.

MS. FERNANDEZ: Well, what type of measures would you suggest?

MR. STUART: Well, in my opening remarks, for example, I suggested principles, and in the paper I handed out, there are corollaries. And it says these principles, in order to achieve them, these are the sorts of things that we have to see in a proposal that comes back to us, because, otherwise, what I fear is you're giving the regions discretion to do things regionally, which I think is inevitable, and I think it's important, but if you don't give them enough guidance, you're going to get back a hodge-podge of proposals from the regions.

And one of the things that you have to guard against is when the regions come back with proposals that are regionalized, they still have to work together. For example, CRR allocation and those sorts of things, if you have a resource that's going from on RTO to load in another, that process is going to have to work in conjunction, that allocation process and the obtaining CRR process.

But the other real difficulty is that if you don't give people a lot of direction and a lot of guidance, you're going to end up with a negotiating process at the RTO level. I know there is a desire to let that happen to a certain extent, but there's not equal bargaining power at the RTOs when this gets -- and we are sort of at the bottom of the heap in that process.

And it's not the RTO doesn't listen to us and that we don't get our input; we do; we're there; we're giving our input, but at the end of the day and at the bottom on critical key issues, the people that matter to the RTO are the people who bring the facilities to the RTO.

I come for free. When my transmission owner joins an RTO, I come along and I don't have any choice. What the RTO needs to succeed is owners and facilities, so on the critical issues, I don't have equal bargaining power, and it's important that there's clear guidance so that that doesn't run the process, that unequal bargaining power.

MS. FERNANDEZ: Mr. Mesa?

MR. MESA: So, I mean, I agree with a lot of what you just said there, Michael, but it seemed like there is some conflicting information, because if we go down the path of, okay, FERC, provides us principles and allow regional differences and we'll bring forward solutions, but still we need some measureables to know what to bring you.

That kind of sounds like, well, tell us what the solutions are, which kind of contradicts the first goal, which was let's see the principles. So I would caution FERC not to go too far down the path of specific deliverables, because I think we'll fall right back into the original trap which was cause for a lot of the concerns, which is a standard cookie cutter across the country may not solve all the problems in the right way in the different regions.

So I would go back to my prime directive and the secondary directive, and I think most of the things that we've captured today address the primary, which is do no harm. And I would say that especially in light of some of the discussions on the auction, or the allocation of CRRs, we really need to be watchful of the prime directive there.

We don't want to undermine or unravel some of the past deals, the contracts, preexisting contracts through that mechanism. So I guess that's the caution there.

On the secondary directive, that is provide certainty. I think we need to see some indication that as the regional solutions are brought forward, that we know that they -- if approved by FERC, that they will stand and not get overturned or overruled by something else.

And I think this is especially important for non-jurisdictional entities. We need to create an environment that is safe for non-jurisdictional to participate in this, and get a comprehensive package.

I would also say that having comprehensive solutions is also one of the guiding principles that we should be using. In the discussion today, throughout, on load pockets, I think the holistic approach there is not just rely on price signals out of LMP to solve those types of problems.

MS. FERNANDEZ: Mr. Keller, and I'll warn you, we're getting really short on time.

MR. KELLER: Okay, I'll be brief. The principles match very closely to the list of principles that I had come in here with, and the first one, though, allowing CRR allocation, is a little weak wording as far as I'm concerned. I'd like to see it a little more than just allowing.

MS. FERNANDEZ: We probably would play with the wording some more if we weren't doing it right today.

MR. KELLER: I think you understand where I'm coming from there. And facilitating new investment, I think is very important; that, you know, congestion problems that we have, as I think has been mentioned a number of times today, the real solution is to build facilities and build the right facilities in the right places.

And we want to make sure that we've got a CRR process that doesn't inhibit that, but, indeed, encourages that.

MR. DAUPHINAIS: One concern I have with the principles is that it begins to start looking like a standard market concept rather than a standard market design. I think it's important that the Commission set a minimum standard design in this.

And they can allow regional diversity or differences, providing those regions come in and make a demonstration that what they're proposing is equal to or superior to the default proposal by the Commission in the final SMD rule.

The 888 approach basically is what I'm suggesting, rather than an Order 2000 approach.

In regard -- I'm not going to get into length on the principles. Some of what I would say is covered; it was covered in my opening remarks and other remarks I've already made.

The two things I would leave you with are: One, I'd add an additional principle, which is the market value of the transmission system should remain with those who ultimately pay for the transmission system.

And lastly, it's very important in all this, that market power be addressed and the Commission be very vigilant on the market power issue. It won't work if entities are able to exploit market power under this structure. Thank you.

MR. BRUGGEMAN: My comments are similar to James who just proceeded me. On the principles, I would again like to see a full auction as a principle.

I'm really impressed and very interested in this process. Going through the principles, I think, is very important. They have us focus on the most important issues, but I worry about a dilution from the NOPR as it's stated now.

There are many parts of the NOPR that are really applicable anywhere and everywhere. And I think if you are just focusing on principles and not having more detail as to what's needed to implement those principles, is going to result in a lot of argument on whether or not the principles have been met. That's all I have.

MS. FERNANDEZ: Thank you. With that, as I said, we are very short of time, and we're going to start promptly at ten after 4:00. Thank you.

(Recess.)

MS. FERNANDEZ: Are we ready on the speaker phone?

(Technical difficulties.)

MS. FERNANDEZ: Let's see. We are supposed to have Bob Graniere--and actually as sort of a general matter, for those who are on the phones you need to speak from the handset not a speaker phone.

I would like to check to see if the people who are supposed to be there are there.

Is Bob Graniere there?

MR. GRANIERE [BY PHONE]: I'm here.

MS. FERNANDEZ: Wally Gibson?

MR. GIBSON [BY PHONE]: Yes.

MS. FERNANDEZ: And Stefan Brown.

MR. BROWN [BY PHONE]: Yes.

MS. FERNANDEZ: Okay, so everyone's here. And can you hear us?

UNIDENTIFIED SPEAKER: I can hear you perfectly.

UNIDENTIFIED SPEAKER: Yes, I can.

MS. FERNANDEZ: If you're on the phone, we have a transcript being made so that, if you would say who you are when you start speaking.

Let's start with Mr. Proctor at this end.

MR. PROCTOR: Good late afternoon. We are all tired, and probably a lot has been said today but one of the major transition issues that we have been thinking about with respect to allocating CRRs in such a way that all customers receive CRRs commensurate with their existing rights on the transmission system is the effect of loop flow on the availability of CRRs that will be revenue adequate.

I have been told by many--and I don't know for sure--that one reason that you may not be able to allocate all of what everybody has is because of the loop flows on the system.

So while you may have sufficient CRRs to cover what was sold or reserved for native load within each control area, there may be insufficient CRRs to cover both transmission sold and loop flows from those sales.

One way to deal with this is to allocate CRRs within each control area to internal load, and out and through transactions that are under contract.

Where there is insufficient transmission capacity to cover these transactions along with the loop flows to prorate down the allocation of flow gate CRRs for the loop flows, alternatively the flow gate CRRs for the loop flows could be auctioned.

I might say that one of the benefits of an auction, depending on how you distribute the auction revenues, is that you account for those loop flows.

Now either of those solutions seem reasonable to allocating scarce CRRs where there is an issue--but there is an issue of who will pay.

If the loop flows were only from internal load transmission customers of each control area, then the prorating of the CRRs would impact most heavily those transmission systems that are leaning on other systems. In this case, the alternative to prorating or auctioning CRRs would be for the internal load customers of one control area to invest in the upgrades needed to expand the CRRs available in neighboring transmission systems.

That works well with internal loads, but a more serious allocation problem arises when sales of through transmission service are involved and parallel path flows impact flow gates in the adjoining transmission systems.

If the CRR allocation is prorated down, then who is going to be at risk for the congestion cost? It will be the transmission customer? Or will it be the transmission owner that sold those transmission rights?

In these cases, there may be several transmission providers involved along the contract path. If the transmission providers are at risk, for what share will each of these transmission providers be at risk?

If the transmission customer is at risk, are we talking about abrogating contracts?

Similarly, if there was an auction of these CRRs, who would bid? Would the transmission customer, or the transmission provider?

Finally, the solution is additional investment participant funding to relieve the congestion, who would contribute? Transmission customers, or transmission providers?

Those are difficult, difficult transition issues that have to do with the fact that FERC is moving from a contract path based system to a flow based system, and it is one that needs to be addressed and I think ultimately needs to be resolved.

Thank you.

MR. KAHAL: Good afternoon, my name is Matt Kahal. I am here representing the Arkansas Public Service Commission.

I have been listening to the presentations today and trying to take notes, and I am much heartened by the fact that many of the speakers that I've heard today have supported the concept of there being some regional flexibility with regard to how the CRR framework is implemented.

I just want to give the perspective of the Arkansas Public Service Commission. It is important to understand that Arkansas is served by integrated, fully regulated utilities that, generally speaking, self-supply for at least 85 to 95 percent of their requirements.

That just is not likely to change at any time in the foreseeable future. Consequently, as a result, the Arkansas Commission does view the relative importance of moving to the LMP CRR paradigm probably differently than those who might reside in places like New England or the Midwest or the Mid Atlantic Region.

Consequently, the Arkansas Public Service Commission has supported the concept of the direct allocation to native load of the CRRs. We think that that is going to best address the issue of cost shifting, which we regard as the major risk.

I would note and bring to your attention that Charles River has completed a study on behalf of the CRUC states. In that, Charles River has estimated that the congestion costs are on the order of $700 million, or would be on the order of $700 million a year in congestion costs. Over 10 years, that is $7 billion. In the immortal words of Everett Dirksen, "That's real money."

Consequently, if the allocation of CRRs are not handled in a way that protects customers, this is a significant financial risk.

Furthermore, I guess I am concerned that even that estimate there's a risk that that could be too low. It is a modeling study, and modeling studies tend to make ideal assumptions such as no market power and things like that.

Just from observing PJM, I have noticed that since the inception--the first year being 1998--there have been big increases in congestion costs within PJM. So even estimates like the $700 million per year could be too low.

I would like to I guess echo the bottom line of the previous speaker from Bonneville of Do No Harm. We think that is a good guiding principle.

Finally, I might observe that I think the states--and that would include us--what this has highlighted today is that it is a lot of work for us to do in terms of coming up to speed on the technical issues.

It is very important that the state regulator voices be heard in this process as the details are fleshed out hopefully in a flexible process with the RTOs.

Thank you, very much.

MR. LAWTON: Yes. I am here to represent Dr. Robert Graniere of the NRI who is currently in Japan and on the speakerphone.

His CRR Report was approved by the NRI Research Advisory Committee and the NRI Board of Directors as one of two reports in the area of concerns of state regulators.

Dr. Graniere's report observes in part that CRRs as proposed may not work as well as desired if the generation market is not competitive, or if transmission resources are not adequate, or if a secondary CRR auction market exists with no restrictions on entry or exit and no obligation to serve.

A clear example can be seen from the role of the speculator in the secondary markets. How would a speculator act? A speculator has no obligation to delivery power. A speculator undertakes a rational risk in the anticipation that a sizeable financial reward exists.

A speculator could use a create-your-own congestion approach and then try to profit from it.

A second strategy could be to sell no CRR before its time. Here a speculator with no obligation to serve would time the market to sell CRRs when the demand was at its highest point. Other than guessing wrong about the auction price, the speculator only has a price maximization strategy.

The speculator could hold for the highest CRR auction price, sell, and exist the market.

Speculators have no incentive to participate in load congestion markets. Construction-based congestion solutions would occur after the speculated profits are extracted by the speculator.

Thank you.

MS. FERNANDEZ: I guess Mr. Gibson by phone.

MR. GIBSON [BY PHONE]: Wally Gibson, Northwest

Power Planning Council.

Sorry, this is going to be a little weird because I'm getting feedback on my phone.

First of all, I want to note that I'm not speaking for any of the states in the Northwest that actually have to make the decisions about the RTOs. Those decisions are made by individual State Commissions.

The main point I would like to make about the Northwest is that--and I think it has been made by Rich Bayless earlier and Phil Mesa as well--that there is a large, actually almost a preponderant amount of transmission covered by nonjurisdictional entities, particularly Bonneville Power Administration.

So this question of allocation of the CRRs is not just an IOU Native Load issue, it is also a question of all the public agency customers of the Bonneville Power Administration.

This is actually not just a Northwest issue; it is a West-wide problem, a West-wide issue, I should say, because of the power marketing, other power marketing agencies in the West.

I think that RTO West has come to a reasonable solution for dealing with the allocation of CRRs, or in our case FTOs or CTRs, as we call them, to existing load, holding of existing load service obligations and existing contracts.

Rich Bayless described the process earlier today, but it actually allows for all of the existing rights' holders to maintain their existing contracts or existing rights without any transition required if they so wish. But it also provides incentives for conversion to the kind of financial rights that are envisioned under SMD to the extent that people see them as valuable choices to make.

I think that is an essential element that needs to be maintained for any RTOs to go forward in the Northwest, and probably in the larger parts of the West as well.

I think a similar problem would exist in the West Connect Area because of the large presence of public power down there.

So I will just leave it at that at this point. Thank you.

MS. FERNANDEZ: Mr. Brown?

MR. BROWN [BY PHONE]: Yes. Stefan Brown with the Oregon Public Utility Commission.

I haven't listened to the preceding panel, so I may be repeating (inaudible).

MS. FERNANDEZ: We can't hear you.

MR. BROWN [BY PHONE]: (Inaudible).

Can you hear me now? Hello? Hello?

MS. FERNANDEZ: That's better.

UNIDENTIFIED PHONE SPEAKER: I can hear you, Stefan.

MR. BROWN [BY PHONE]: Okay, I will use the speaker phone. Can you hear me now?

MS. FERNANDEZ: That's better.

MR. BROWN [BY PHONE]: Wally, can you hear me?

MR. GIBSON [BY PHONE]: I can hear you, but I'm not sure anybody else can hear you.

MS. FERNANDEZ: We can hear you. Go ahead.

MR. GIBSON [BY PHONE]: I can see Alice Fernandez on the Web Cast looking around desperately.

MR. BROWN [BY PHONE]: Okay, I'll try it again.

MR. GIBSON [BY PHONE]: I think it is their problem and not ours.

MR. BROWN [BY PHONE]: Okay, why don't you talk, Wally, and see if they can hear you?

MR. GRANIERE [BY PHONE]: Stefan, go ahead. We can hear you.

MR. GIBSON [BY PHONE]: I am talking.

MR. BROWN [BY PHONE]: I'm watching the Web Cast with the time delayed by about 20 seconds or so. I see somebody running around checking microphones.

MR. GRANIERE [BY PHONE]: Stefan, go ahead.

MS. FERNANDEZ: Go ahead.

MR. GIBSON [BY PHONE]: So you have been watching the Web Cast?

MR. BROWN [BY PHONE]: I have been watching the Web Cast intermittently.

(Laughter.)

MR. GRANIERE [BY PHONE]: Commissioner Ervin? Shall we move on?

MS. FERNANDEZ: Mr. Brown, did you have an opening statement?

UNIDENTIFIED PHONE SPEAKER: --at least I kind of got the gist of what was going on. I guess we should keep talking.

MS. FERNANDEZ: Maybe we should move on.

UNIDENTIFIED PHONE SPEAKER: I don't know whether Bob Graniere is not there, I presume?

MR. GRANIERE [BY PHONE]: I'm here.

UNIDENTIFIED PHONE SPEAKER: Hi, Bob.

MR. GRANIERE [BY PHONE]: Well, we could all talk to each other.

UNIDENTIFIED PHONE SPEAKER: We can talk to each other, right.

UNIDENTIFIED PHONE SPEAKER: As I say, I'm watching the Web Cast. There seems to be nothing happening there. Let me just turn it up. This is time-delayed. I can't listen to the phone at the same time.

MS. FERNANDEZ: Commissioner Ervin?

MR. ERVIN: That was so interesting, I hate to interrupt.

UNIDENTIFIED PHONE SPEAKER: Alice Fernandez is saying maybe we ought to move on.

UNIDENTIFIED PHONE SPEAKER: Why doesn't someone there pick up the phone and see if there's actually, you know--

UNIDENTIFIED PHONE SPEAKER: Oh, wait a minute. Now they're hearing my--they're hearing us.

UNIDENTIFIED PHONE SPEAKER: You can hear us now?

MS. FERNANDEZ: Yes.

UNIDENTIFIED PHONE SPEAKER: Hello, FERC?

MS. FERNANDEZ: We've been hearing you for awhile. We were sort of at the point where, Mr. Brown, this is sort of your last chance for an opening statement.

UNIDENTIFIED PHONE SPEAKER: They're enjoying what we just said.

(Laughter.)

MS. FERNANDEZ: They can't hear us? Okay, we're going to move on to Commissioner Ervin.

MR. ERVIN: All right, and I will try to talk loud enough that I override them as they keep going on their conversation.

Like everybody else, I appreciate the chance to come and speak with you briefly today. I threatened Ed Meyers with disclaimers at the beginning, and they are, first, that--

UNIDENTIFIED PHONE SPEAKER: Okay, Alice, this is Wally. We can't hear you on the phone but I can hear you on the Web Cast.

MS. McKINNEY: Do you want me to just cut the phone off? I'm sorry, we are going to have to cut off the phone. This phone is not going to work.

UNIDENTIFIED PHONE SPEAKER: I think we just got hung up on. Wally?

UNIDENTIFIED PHONE SPEAKER: I'm still here.

UNIDENTIFIED PHONE SPEAKER: Don't talk.

MR. ERVIN: The two disclaimers that I think I need to make up front are, first of all, that we have filed comments that question a number of the legal and policy justifications for the whole proposal, and I don't want my presence here to be construed as any sort of waiver of those comments.

I don't propose to discuss them because I understand the purpose of the meeting, and I am perfectly prepared to go forward on that basis, but I don't want my silence on some of those other questions to be construed as consent.

Secondly, I am speaking here only for myself. I am not the official representative of the North Carolina Commission. And, like other speakers, a lot of my thoughts on these subjects are relatively preliminary at this point. So you can add uncertainty to my general lack of technical expertise and probably discount a lot of what I have got to say here today.

However, it does seem to me that there are several things that could be pointed out appropriately, like the situation that Matt Kahal described in Arkansas. North Carolina remains a vertically integrated, fully regulated State as far as IOUs are concerned.

We do have a significant municipal and cooperative presence, but they own a significant amount of generation themselves and also have pre-existing contract rights. So some of the concerns I express here I think are applicable to some extent to those folks today, although we don't regulate them.

At the present time it seems that our IOU customers have effectively certainty of deliverability and certainty of price. And to the extent that any uncertainties exist, we have the authority to require the construction of generation, and we have authority to require the construction of transmission.

So that there are things we can do to eliminate any problems that arise if uncertainty occurs.

Our concern with the CRR treatment in the NOPR is that it introduces elements of--clearly introduces elements of price uncertainty, and it may introduce elements of deliverability uncertainty as well depending on how ya'll ultimately resolve the question that was discussed this morning about whether to give physical rights to CRR-holders.

Basically in a nutshell we are not excited at all about any sort of allocation process. It seems to us that what we need to have from our customers coming out of any SMD proposal is for our customers to be no worse off than they are now. And if they are faced with deliverability problems, if they are faced with the possibility of actually paying congestion charges over and above those that are inherent in the dispatch order, it seems to me that our customers are worse off and an auction proposal may very well produce that result.

Our customers have paid for the transmission assets that serve them. And to the extent that they are at risk of losing the ability to use those assets without additional congestion costs, it is hard for us to see how anything good comes of that. And an auction introduces elements of risk that exactly that will occur.

With respect to the issue of allocation--and obviously if you don't like auction, you probably tend to prefer allocation--we think that any allocation, and there are probably several ways you can do it, and I don't want to get into the length of the allocation period or anything of that nature, but I do tend to think that longer allocation periods probably serve our interests better.

We want to make sure that we don't lose access to transmission capacity that our customers are paying for now. A lot of the concerns that were expressed earlier by the representative of TAPS and others resonate with me pretty strongly.

Our customers have paid for the transmission system that serves North Carolina. To the extent that we don't retain CRRs commensurate with what we paid for, we have come out worse.

Similarly, I find the simultaneous feasibility study we've discussed all day pretty interesting. I have similar concerns about the simultaneous feasibility provisions in the NOPR because it seems to me if I'm reading them correctly that there is a risk that our customers may not even get the benefit of the peak allocation process that's described in the NOPR.

To echo Matt Kahal, our principal emphasis is do no harm. I understand that this Commission's principal job is to facilitate improvements in the wholesale market. What I want to emphasize to you is that you should do whatever you feel like you need to do for the wholesale market in such a way that it does not have adverse impacts on the retail markets that we regulate. And I am concerned for reasons that I'll be glad to go into in more detail later that an auction would do that and that certain aspects of your allocation proposal would cause harm as well.

Thank you.

MR. THOMAS: Thank you for the opportunity to speak here this late afternoon. I'm Glen Thomas from the Pennsylvania Public Utility Commission and I am presenting my testimony this afternoon on behalf of our entire Commission, the entire Pennsylvania Public Utility Commission that is.

From the outset I want to express my thanks on behalf of our Commission for the extraordinary level of cooperation that we have received from FERC from the time we set foot on the path to retail competition until the present.

It also would be appropriate to commend FERC for their extraordinary outreach efforts that have been undertaken during this SMD process. It has indeed been extraordinary and it has indeed been a very fruitful discussion I believe.

But starting from the early 1990s, shortly after the passage of the Energy Policy Act in 1992, your Commission has sought ways to assure open access to the transmission grid with comparability of rates, terms and conditions of service. The Pennsylvania PUC views the SMD NOPR as a logical and necessary progression along that path.

I would encourage the Commission to remain steadfast in its resolve to complete the rulemaking in due course. The longer that issue is addressed and the SMD remain unresolved, the longer that the troubling cloud will hang over this energy sector.

Investments in our electricity infrastructure are needed in all areas of the country. However, financial commitments will not be made in an era of such uncertainty. Time is quickly becoming of the essence.

We must be clear on a very basic point. Not all states have similar views, a fact of which we all are well aware. And not all regions are prepared to accept wholesale or retail access at the pace that our Commission has. While bearing in mind that Pennsylvania is speaking from what may be a different perspective, we hope that the various regions will be flexible and in turn that your Commission will be able to accept and work with the various positions placed before you.

From Pennsylvania's perspective, standard market design is ultimately essential to the successful operation of both wholesale and retail markets in the Eastern Interconnection. The transmission grid is a superhighway over which the commerce of energy moves. Access to that highway and the rules of the road must be clear, fair and economically rational.

CRRs are financial rights that will provide protection against the cost of congestion for transmission service in the day-ahead markets.

I have addressed in greater detail the Pennsylvania PUC's position in my written testimony. However, I would like to summarize our views specifically on CRRs. I would also note that we've also answered the questions that were specifically posted in that written testimony as well.

First, CRRs should be financial rights used as a hedging tool against congestion costs, not physical rights used as a scheduling priority mechanism.

Secondly, your Commission must address concerns about interregional load transfers associated with allowing for regional variations on the allocation of CRRs to load.

And thirdly, I'd want to emphasize the importance of protecting against the use of CRRs to exercise market power, certainly something that has been discussed earlier today.

The continued development of retail electric competition in Pennsylvania and in other states depends upon vibrant transparent wholesale markets and an interstate transmission grid that is not controlled by parochial interests.

This is not to say that there should not be direct and proactive market monitoring. Indeed, market monitoring is critical to the ultimate success of this rulemaking. We urge your Commission to take this opportunity to create the context in which consensual rules are determined for them to stay in the game and assure that those rules of the road are followed and adhered to.

Again, I thank you for the opportunity and look forward to any questions you may have.

MS. FERNANDEZ: Does anyone want to start?

CHAIRMAN WOOD: I want to thank y'all for coming. We always save the best for last.

MR. ERVIN: I thought we were supposed to put them to sleep so they can drive home safely.

(Laughter.)

CHAIRMAN WOOD: Jimmy, you thought actually in kind of summarizing what you'd heard today made a lot of sense to me too and I was watching the Staff through lunch and the afternoon try to codify some principles. And I wondered if there was in your m ind based on what you've seen kind of be developed through the thoughts of the various panelists, if there is a way to actually do the CRR allocation so that it does no harm. Is there a null set there or is there some options in that set of principles that could get there that you think is feasible?

MR. ERVIN: I'm certainly not prepared to say that there is no way to do it. I am not what would be described as a quick study in this area. Glen and his folks have had to live with this kind of system for a number of years, and they know how it works, what I know about it is more of an academic exercise at this point.

I suspect that there may very well be a way to do no harm. I'm not sure that it has been identified yet. We're certainly wiling to give that question some thought. But at bottom, to go back to something that the TAPS representative said earlier today, we are not writing, at least in the Southeast, on a clean slate.

People have existing transmission rights. Some are of a contractual nature. Some are native load expectations. And those rights we think ought to be respected. And to the extent that we throw everything open to the winds, that's something that is very troubling.

So that it seems to me if we're going to go to this kind of system, and as you know, we've got reservations about that. But putting that question aside, if we're going to go about it, I think we do need to identify what people's existing rights are and then try to do as good a job as we can of matching up CRR assignments to what existing uses are.

In addition to that, you've got to give some thought to the notion, some recognition to the fact that at least in our area, it's my understanding that there is reserve capacity in the system now that is not being actually used by somebody. To the extent that that capacity is included in retail rate base and is being paid for by retail customers or at least subject to being paid for by retail customers if a rate case was to be held, then at least it's our position that that's held in trust for retail ratepayers and ought to be treated that way in the CRR world, and I'm not sure the NOPR does that.

CHAIRMAN WOOD: So your thought is they're paying for it today, they ought to get it? Do they need to be paying for it if it's more than they need? Could you put that out for auction?

MR. ERVIN: I think at that point the notion of a residual auction did not bother me when I heard it explained this morning. So that to the extent that a vertically integrated utility that is serving as a load-serving entity feels like that its customers would be better off with some form of auction for some rights, that might very well be a reasonable thing for that utility to do.

Now I think if we went to this type of regimen, one other thing somebody ought to think about is that under our asset transfer statutes at the state level, we might very well view CRRs as something that could not be transferred without some state commission approval.

I haven't thought through that one specifically, but that's an issue that has occurred to me as I've sat here today what our role might be in that under state law and how you reconcile it with your own authority is something that I haven't thought through, but that's at least something I wanted to mention at some point in this discussion.

CHAIRMAN WOOD: Glen, just to kind of shift to the retail unbundled environment, one of the things, and I think we got a case, an industrial, might have even been in

Pennsylvania, the Occidental? That was Delaware. Okay. It was in PJM.

The difficulty of a customer to exercise his or her rights to do retail choice with the whole reconfiguration of FTRs, CRRs, whatever we're going to call them, have you seen that that has been an impediment in the Pennsylvania as y'all have opened up that if a retail customer switches to a different supplier that they've got to reconfigure these congestion revenue rights or FTRs to make the deal work?

I hadn't heard much about it pro or con, but somebody earlier today, maybe it was one of the industrial witnesses, made me think about that, and I wondered if Pennsylvania, you guys had heard anything about that?

MR. THOMAS: We've been presented with several stumbling blocks, and that has not been one of them. If it was one, we'd probably be hearing about it. That's the way things usually go.

But, no. I could probably point to several other stumbling blocks as part of the technical transition and the phaseout. But getting the transmission rights to move with the load has worked actually pretty smoothly, at least from my perspective.

CHAIRMAN WOOD: One of the things over the past couple of years, and I was talking to Nora about this before she stepped out, was the congestion in the PJM grid has gone up in the past couple of years. And I just wondered from the state regulator perspective if there was anything -- I mean, you have to be the siting approval guy, so I assume you'll hear about it before anybody does -- but is there anything about this unbundled system with these allocation of rights and all of that affects the level of congestion? And does it make it worse or better, or is there?

You know, we hear that it doesn't completely solve it because the price signals are signals, but they don't get the construction built. How can we get congestion uncontested by use of this system? Or do we have to just stick to centralized planning to fix the problem?

MR. THOMAS: I don't think we do. I think what you do is you create a system where demand, generation and transmission can compete with each other. And you set the table so that you can get around the congestion, you know, in essence through those three means. Develop generation that's more agile, that hits the load pockets.

The same with transmission. Build additional line or reduce your demand. So if you set up a system that can exercise efficiencies and allow those three mechanisms to compete against each other based on market signals, I think that's what we're shooting for in Pennsylvania and in PJM.

CHAIRMAN WOOD: Do you feel like that's starting to happen?

MR. THOMAS: The seeds are there. Certainly I think probably the biggest challenge right now is the lack of clarity that certainly exists in the rules of the game. And to the extent that there's this cloud in the wholesale marketplace in terms of what the rules are going to be moving forward, that probably prevents some of the investments, or at least puts a cloud on some of the investments that are going to be necessary to move this market forward.

Are we seeing more examples of it? Sure. We are seeing more distributed generation. We are seeing more demand responsiveness. And you can talk to a lot of the industrial consumers in Pennsylvania and they're getting incredibly sophisticated about playing demand off of generation off of transmission.

It's going to be a long transition until we get to the ultimately efficient system, but I think it's very important that we keep taking these steps along that road to get there.

CHAIRMAN WOOD: Mr. Proctor, the loopflow issue is not unique to Missouri, but I'm sure y'all have been right in the crossroads of power grids sure makes it a big issue there. Kind of flesh out a little bit more what you had said at the front end here about how you at the core address that issue through the CRR allocation. I mean, I thought your prescription for it was actually kind of creative, and I wanted to kind of think through that out loud with you.

MR. PROCTOR: Right. I think it works well. Basically what I'm saying is ultimately I think you need to work towards an auction where the revenues from that auction go to the transmission owner where the congestion is. And that is in essence a payment for loopflow. Because if I've got a point-to-point -- well, hate to use that terminology, but a point-to-point CRR that I'm having to purchase and it flows on somebody else's system in essence, and that's congested, that part of their system is congested, I can't say that I've paid for it. I've paid for the system that I'm on. This can be an internal transaction, internal generator to an internal load within a control area that flows out on someone else's system. I haven't paid for it, okay, but I'm using it.

Now other people haven't paid for their use on my system as well. So I think ultimately, as you go to an auction, that you get those kinds of payments that are naturally going to take place if you allocate the revenues to the systems where they were congested. So I think ultimately you have to go there. The problem is the transition in getting there, and particularly if you're talking about I'll call it a parallel path flow on an old point-to-point contract path type of transaction.

I cannot -- I mean, the only answer I can give to that one is they retain their physical right for a period of time. Because I don't know who participates in the auction. It is a complicated situation because you're going from that contract path to really a flow-based type of transmission pricing.

I guess the other thing I would add is people talk about eliminating pancake transmission rates, and that's fine. And I know I've heard Alice say this. When you're having to buy CRRs on a long distance transaction, it's going to get pancaked. You're going to have to pay for those along the way. I mean, ultimately, you're going to have to do that.

Loopflow is a major concern in the MISO, and the initial study has not yet been done, but it should be finished in the next month or so where it's looking at will there be enough CRRs there to meet native load and existing transmission contracts, whether they were pre-Order 888 or post-Order 888.

And the big concern is there won't be enough there because of the loopflows on the system. Those are an additional problem with the PJM West and the Midwest ISO because we've created some additional loopflows between RTOs with that particular configuration.

MR. O'NEILL: I can understand the issue with seams, but why can't MISO take care of the internalized loopflow problems? I mean the ones inside of MISO. I mean, we thought that that's what these CRRs and the whole FTR stuff would work. I mean, it would take into account the loopflows inside the RTOs.

The seams problems are different, but.

MR. PROCTOR: Remember, you had two objectives there, and one was to kind of the no-harm objective.

MR. O'NEILL: Right.

MR. PROCTOR: And the second one was the revenue adequacy objective, which really limits the number of CRRs. And if those aren't in conflict, then of course you can take care of the problem. It's where those two come into conflict with one another and now you have to start pro rating down if you're allocating CRRs or go to an auction something along that line.

What I'm -- I think the other thing that's really key here is to look at those and look at them in terms of somebody on System A having to contribute to investment to upgrade something on System B because they are contributing to the congestion on that system. I think that is a real key because -- and if you don't get to that, if you never get to that point, then I don't think any of this is going to work.

I think it's got to -- you've got to do that. Now another way of course you know that you can treat it is just to throw it into one big, you know, there aren't any loopflows because we've just kind of made it all one big system. But we're not looking forward to going that route particularly.

MR. O'NEILL: And as we've gone through the day we've found that the resource adequacy and the simultaneous feasibility test can be interpreted in different ways. And so call options on generators and things like that can't solve the problems?

MR. PROCTOR: At this point I don't know the answer to that. I know the second big issue in MISO is the issue about whether it's options or obligations. And there's a real concern about that. The perspective -- and I appreciate the things that have been shared here today about providing options but getting an up-front payment from them.

But the perspective there is I was generating, and because of my commitment to generation to serve my load from a specific plant, I was providing a counterflow. And there was a direct connection between me as a generator and the load. But there was this transmission business over here that now has been separated by Order 888.

They looked at that transaction. They said, hey, there's some additional transmission to sell here. And they sold it.

I didn't get an up-front payment for it. I didn't get paid for providing a counterflow.

MR. O'NEILL: Who are you? The generator?

MR. PROCTOR: Yes, the generator of load, an LSE-type. I didn't get an up-front payment for it, and I think ultimately --

MR. O'NEILL: I mean, if that's an independent generator, independent of the transmission company, that generator should be compensated.

MR. PROCTOR: Yes, it should, and I think ultimately what you're proposing or what I'm hearing today is a proposal or proposals in which that would occur.

MR. O'NEILL: I mean, I think what I was hearing was that when the system was vertically integrated, the transmission owner would sell transmission rights that included the redispatch of some of his generation to make the system simultaneously feasible.

MR. PROCTOR: Correct.

MR. O'NEILL: Those contracts need to be honored, and you need to identify the generators that need to be run in order to make those happen. And then in a vertically-separated world, the generators would get call payments for standing ready to be dispatched to create the transmission.

There are several places around the country, several load pockets where there are nomograms that say that you can't say that you can't import more than so much capacity into a region unless you have certain generators running.

And they are reasonably well known. The one that we bandy around here is called the San Francisco nomogram, which was made famous for other reasons. I think, in some sense, I would include all of those issues in transmission rights and the ability to sell transmission rights and to honor existing rights. And for the vertically-integrated utilities in the South, I think the same thing is true.

I mean, some of the transmission rights may actually have to be coupled with call options on generators, and for vertical companies, that's not a difficult process to implement.

MS. FERNANDEZ: Did you have a question?

MR. GRAMLICH: Well, NRRI had a paper that you mentioned, Mr. Lawton, and we looked at that paper, and I guess I had a few questions about it.

There are a number of statements in there that -- I recognize that these are complicated issues and this is all kind of a lot of these concepts are new and we're all sort of learning about this.

But there are a lot of statements in there that really -- statements about what the NOPR says that a lot of us just don't recognize as being in the NOPR, and otherwise seem to be somewhat misleading. So I just wanted to highlight some of those and see what your thoughts were on what the next round of this paper were or what your purposes were for the next steps of that.

One issue that you did mention now was the restrictions on who gets CRRs, like the horror stories of speculators coming in and using the CRRs for various devious purposes.

The discussion on the last panel was about the question of if rights are allocated to existing customers, then many of those concerns go away. And there are also mitigation, market power mitigation features of SMD that would deal with those issues. That's one issue.

The paper talks about access charges as if they're sort of daily or hourly, which is not right.

LMPs, I guess, in real time would trigger transmission customers to initiate cancellation of their network access service, I mean, that doesn't happen in the proposal.

There's a new term, the controlling node. I guess where are we going with this paper? I mean, can we work out some of these issues, maybe working with our staff?

MR. LAWTON: Sure. I guess that wherever there is any confusion, I'm pleased to do that and to work out a way for Bob Graniere to deal directly with you or whomever you designate.

Obviously, if no speculators arise, then it would become less of a problem, but a speculator is clearly someone who feels that if they do arise, they are undertaking a high risk business proposition, and they are doing it because they're betting. They expect some failures, so they expect more reward.

They are undertaking a risky strategy, but they are evidently doing it for a rational reason, and that rational reason would be congestion.

MR. O'NEILL: As I heard your presentation, I got the feeling that the speculator is somebody that buys low and sells high. And we all want to do that.

I mean, is there anything, is there any special way that the speculator is going to make money, other than knowing when to buy low and sell high?

MR. LAWTON: Buying low and selling high works in a lot of situations.

MR. O'NEILL: Well, I mean, I'll be doing it, if I could figure it out. But what do you think the speculator is going to bring to this process that's going to give him an insight into when to buy low and sell high?

MR. LAWTON: The same kind of knowledge that existed in California with different substantive examples, but the same kind of knowledge of understanding the system.

4

I mean, obviously if someone can't think of a way to arbitrage, to use the word incorrectly -- but if someone can't really arbitrage the system, the speculator class won't arise.

But obviously if someone gets involved, they clearly think that if they buy it, they're going to pay me a premium to get it from me, they're not doing it for charity; they're expecting they're going to make money. They might be right; they might be wrong, but they're going to factor in a high-risk premium for that.

MR. O'NEILL: Do you think that in an LMP system, you can get paid to relieve fictional congestion?

MR. LAWTON: I'm sorry, I didn't hear the first part.

MR. O'NEILL: I thought you were alluding to examples in California where you can get paid to relieve fictional congestion.

MR. LAWTON: I'm saying that to the same extent that someone could scope out a system, you can scope out any system, and in this case, if the system is perfectly designed, there's no room for someone to exploit those.

But why would someone buy? I mean, why would a speculator come onboard? It's not for charity.

MR. MEAD: Absolutely. I guess I wasn't sure what harm you thought might arise.

MR. LAWTON: The retail prices would eventually go up. If somebody is making more money than ordinarily would have been the case, and if it's an insignificant amount of money or if it's a fraction of a fraction of a load, it may not be significant.

But to the extent that that's not true, it could cause state retail rates to go up.

MR. MEAD: Since who holds CRRs doesn't affect what the dispatch is, it wasn't clear to me how any speculative activity in the purchase and sale of CRRs was going to have any effect on energy prices.

MR. LAWTON: Well, to the extent that you could control a bottleneck, that would have an impact.

MR. MEAD: I guess that's why I'm confused, because the operation of the system is not controlled at all by who holds the CRR. Just because I hold the CRR doesn't allow me to withhold a transmission capacity. So it wasn't clear to me how -- you know, again, how holding CRRs or any speculative activity on that was going to change energy prices.

MR. LAWTON: Just by the ability to sell as high as they can, to have scoped out a system, to have been correct in scoping out the system, but to have scoped out a system and said I believe I can get a larger than normal, a speculator's profit in a situation that other people wouldn't enjoy.

MR. HEGERLE: I guess I'm missing a more fundamental point. What the NOPR talks about and what we talked about a lot today was allocating CRRs to the existing users of the system.

To the extent that those customers hold onto their CRRs, I just don't see the problem arising. And the state commissions certainly have a choice in saying I want my utilities to keep them to protect my retail customers.

MR. LAWTON: One of the conditions was to the extent that a secondary CRR auction exists, you just described a situation where one doesn't exist.

MR. HEGERLE: Right, but the load in that instance had decided in that instance, I guess, with the blessing of their state commission, that it would be better for them to release those CRRs, to auction them, than to hold onto them, at which point, why would it matter? What would be the gain then? They would have profited by what they sold.

MR. LAWTON: Yes, they would have had initial profit to meet some need of their's, but why would I buy them unless I thought I can do better?

MR. HEGERLE: Well, I agree, but isn't that what competition is all about?

MR. LAWTON: Right, so if I come in thinking I can do better than the person who released the load, I'm doing it, I believe, with what would be a high-risk strategy, and I'm going to expect to get a higher return out of it.

MR. HEGERLE: And to the extent --

MR. LAWTON: You asked a factual question. I'm either going to be right or wrong, but that's my expectation. I have scoped out the system and I've done something rational.

MS. FERNANDEZ: Kevin?

MR. KELLY: I wanted to ask a question of Chairman Thomas and Commissioner Ervin.

It goes to the value of regional diversity versus standardization. This whole effort of SMD started a year ago where we had something called RTO Week. And people came in and expressed deep concerns that RTOs were actually forming with very different rules that were either repeating the mistakes of the past or even if the market designs were good and not proven to be flawed, were incompatible with one another, making it difficult to trade from PJM to New York to New England, just for an example.

And so there was really a big call for standardization. And now as we attempt to get to standardization, there's a big call for regional diversity.

And it's really a dilemma. Clearly there are some areas where regional diversity would be good, and other areas where standardization would be good, and this question probably is not just a CRR question; it probably applies to any elements of our proposal.

But at least as far as CRR goes, or if you care to broaden it to other area, how would you advise our Commissioners, which is what we have to do, to think about how to balance off those two competing goals?

MR. ERVIN: I'll be glad to give you a short answer, but I think in my own defense, I appeared at RTO Week, and I expressed some skepticism about whether the cost even justified the exercise in the Southeast.

So, I mean, I don't want to be portrayed as having called for standardization at the time, because I didn't. But to answer your question directly, I think the thing that we need to keep in mind is that the situation that Glenn finds himself in is very different from the situation that I find myself in.

And I don't want anything that I advocate before you to somehow harm Glenn's efforts in his jurisdiction, because he has a very different retail market than I have.

I think, at least in the Southeast, there is a feeling that a lot of the -- and it may be an erroneous feeling, but there is a concern that the proposal that is before us now is better attuned to a retail competition model than it is to a vertical integration model.

I understand that the Commission doesn't take that position, but that concern is out there, and I want to lay it before you. I think that you do have considerable regional diversity.

You have retail competition in a good bit of the Northwest, and in the Midwest you have thermal systems with vertical integration in the South, which is different than the PJM-MISO in the New England areas.

And then you have the Western situation that I know just enough about to avoid talking about it.

(Laughter.)

MR. ERVIN: And given that set of circumstances, I am dubious of the notion that one size does, in fact, fit all. I understand that you cannot have total anarchy, but on the other hand, I do think if you adopt a system that suits us, it's likely to have adverse impacts on Glenn.

I think that if you adopt a system that fits Glenn, it's likely to have adverse impacts on us. And so I think one of the things that the Commission needs to very seriously look at is, whatever model you ultimately choose to adopt and after it withstands whatever court challenges that the miscreants among us may choose to launch at it, what impact is it going to have in a particular set of circumstances?

If it hurts the Southeast, have you done -- I mean, have you really carried out your mission? I don't think so.

If you hurt the PJM area, have you carried out your mission? I don't think so.

This is a very diverse country. I'm not sure we have a one-size-fits-all model that's likely to work. If you adopt one, I am concerned about the consequences that it's going to have.

This is a very broad answer and it's subject to all kinds of qualifications. But we do feel like that we are different, and we are concerned that the proposal that is before us does not recognize our differences.

MR. THOMAS: I have a couple of thoughts. I certainly appreciate the comments from my colleague to the right here.

But, you know, I think if I were probably advising -- if my client were FERC and I was advising my client on this one, you know, I would probably try to focus -- recognize the regional differences, but maybe looking for the solution in timing and transition-type mechanisms.

You know, I do see benefits to broad rules over -- and larger markets. I mean, I can sit in Pennsylvania and see days when we'd love to have power from Canada, and see day where we'd love to have power from Tennessee.

You know, I can sit there and see the days when power from Pennsylvania would be very helpful in Tennessee when it's not as helpful in Pennsylvania or not as needed in Pennsylvania.

So certainly the broader concept of creating broader regional markets where energy can move as commerce is a very laudable goal and something certainly that I personally support and the Pennsylvania Commission supports.

But that said -- and to that extent, standardization is a positive thing. Having a common set of rules so that, you know, when a transaction occurs, you know, across a broader area, everybody knows what the rules are, everybody knows how the money flows and everybody knows that at the end of the day, you know, how the accounting is made, and how the system works, not only from a physical perspective, but from a financial perspective.

But that said, in my mind, it's pretty clear, you know, as was alluded to earlier, I mean, certain states are just at different levels of this process and some may never even get into the process in terms of moving to retail competition.

But our see our market and I see the value in creating a broader market, but I don't propose to tell any other state how they should manage their market. I think it's perfectly within a state's prerogative to remain a vertically integrated industry, and I think that needs to be respected as part of any decision.

But certainly to the extent that you can look at timing, it maybe phasing in in different areas and different aspects of this rulemaking, I think that might be a ripe ground for encouraging that regionalization.

MR. GRAMLICH: To follow up on that, one example we've come back to a few times is sort of the Vermont surrounded by the rest of the New England states example, where our goal in SMD was to create something that did work in states that were in different situations, that in some cases did have vertically integrated utilities and in other cases, did not.

What we've developed today are some principles that include standard products, so you can think of after Thanksgiving, pumpkin pie and pecan pie and then in terms of allocating the rights to those products, you can carve that up in different ways.

And the Southeast may carve it up differently from the Northeast or MidAtlantic, but isn't that general concept consistent with what you've been advocating?

MR. THOMAS: From my perspective, I think that is fair. Even within PJM, states have developed different models within PJM. I mean, the Pennsylvania model is a lot different than the New Jersey model and different from Delaware and D.C.

But the point is, you know, we need to work together. The electrons don't recognize the state boundaries, and we have create these rules of the road, so that we're all operating under clear rules, and then let the market do what it can do, at least in our areas.

Mr. ERVIN: I think one of the differences, though, that you do need to keep in mind is that you don't have the Vermont situation in the Southeast. You don't have a mix of retail access and traditional utilities without trying to transfer Virginia to another part of the country. With the exception of Virginia, nobody in the Southeast has gone to retail access. And so it's not really a matter in the Southeast of trying to accommodate a situation where you have some states that have adopted one model and some states that have adopted another. You have a set of circumstances where as best I can tell, nobody has adopted retail access, and I don't see any political support, whatever I might think of it as an academic matter, for moving in that direction.

So I think the regional situation in the Southeast is different than the Vermont or New Hampshire situation that you posited, because there is uniformity in the Southeast in the sense that there's the uniform lack of retail access.

In addition to that, if you look at the way that the north as I understand it, that the PJM area and the Northeast has operated, that is different than the way that we have historically operated. We have not had tight power pools of the type of things that PJM grew out of. We still have utility-by-utility dispatch in the Southeast. That's very different than anything that at least I understand goes on in PJM.

That raises a number of cost shift issues as I think about it. So I think that it's -- I don't want to be too accepting of the notion that we can come up with something that accommodates everybody and that that in turn at a certain level of generality can be applied nationally, because you have different mixes within different regions even though there are some in regions that are generally characterized by retail access that hadn't gone that route, in the Southeast we have none. And that just puts things in a different posture.

MS. FERNANDEZ: Anyone else have any other questions? I think we may be, if we could get our principals. I mean, what we've been talking about with the other panels is trying to come up -- there seemed to be a good deal of sentiment for a lot of regional flexibility.

MS. McKINNEY: If we could pull the Powerpoint up.

MS. FERNANDEZ: And I admit on some of these, there was not unanimity. But maybe if we could go through sort of some of the general principles that we were kind of hearing that it seemed like there was a good deal of interest in perhaps laying out general principles that would be used to, I mean, I think as a basic equity matter, ensure that existing customers have their rights protected and that trying to enunciate what some of those general principles are.

MS. McKINNEY: Would you like for me to read through them very quickly?

MS. FERNANDEZ: Yes.

MS. McKINNEY: Each RTO should develop a transition process that implements these principles:

Allow CRR allocation, require residual and secondary auctions, don't diminish current rights;

Rights must be simultaneously feasible;

Minimize cost shifts, standard product definitions;

Multiple products may be offered, regions could make choices among products;

Facilitate new investment in transmission and generation;

Allocation should not serve as a barrier to entry with benefits of rights following load;

Incentives for conversion of existing contracts, and purely financial CRRs with procedures for rationing, and some general SMD principles;

Seams coordination between RTOs;

The need to assure adequate infrastructure, market design accommodating bilateral transactions, addressing market power, and the proscription to do no harm to current customers.

MS. FERNANDEZ: I guess if anyone has some general reaction if they agree that those are appropriate principles, if others should be added. Chairman Thomas?

MR. THOMAS: First of all I think those principles are really well done, pretty concise and certainly consistent with the Pennsylvania Commission's perspective. I just would probably emphasize two points. One would be I think we need probably a verb stronger than "address the market power". And I know this is preliminary. But I think in general the notion of having a very involved and active watchdog in this area is critical to the ultimate success of CRRs. The market monitoring aspect can't be ignored, and the time and investment and the oversight is going to be critical to the ultimate success.

And the other suggestion I would just throw out for the benefit of the Commission is perhaps using these principles to issue a specific call for comments on these principles by January 10th I think would probably be a helpful message not only to state commissions but other interested parties to give us sort of a focal point so we can better organize our comments, I think would be helpful.

MR. KAHAL: I think that that is a pretty good list of principles. However, I would caution that when one looks at the wording of them, they're rather cryptic and they're going to be interpreted different ways by different people.

For example, on the CRR allocation, I guess sitting here I would be inclined to interpret that as saying allowing the direct allocation of CRRs to the native load ratepayers without having a specific sunset on that methodology, that is like an automatic four years we go to an auction, something like that.

I don't dispute that we don't want what's created here to create barriers to entry. But I think that inevitably, somebody is going to argue that when you adhere to one principle, you do create a barrier to entry. So there's going to inevitably be tradeoffs. So there are those kinds of difficulties.

One thing I would want to add to this list I think is -- and I think that there has been recognition of regional flexibility and it's a question of how far you go. But in implementing the regional flexibility, I'd like to introduce as a principle having a key role for the state regulators who of course have the responsibility for the well being of the retail regulators.

MR. ERVIN: I guess to add to that and subject to the disclaimers that I gave earlier, which are that if we go down this road, what do I think of these things, I would tend to think that a lot of them are written in such a level of generality that it would be hard to argue with them.

I agree with Matt that there are questions of interpretation that would necessarily arise. I, for example, would look at the first one, would interpret that to mean no mandatory auction ever. And that may not be what somebody else means by it. But if that's what it means, and it means instead that a region remains free to allocate CRRs directly to native load, I don't argue with that. I would not want something to be adopted that if another region felt that an auction was appropriate, I don't want to preclude them from doing that if they think that's the best.

To comment on certain of the others, as I've said a number of times, I found the discussion of the simultaneous feasibility issue instructive today and I think that subject needs some further discussion.

With respect to the issue of allocation not being the source of a barrier to entry, let's remember what type of entry we're talking about. Because, for example, my state does not allow retail entry. And so what kind of barrier to entry are you talking about? If you're talking about barriers to wholesale entry, I don't think anybody could argue with that.

MS. FERNANDEZ: I think that one actually came up mainly in the context of states that had retail access, that if customers want to shift to other suppliers, you shouldn't set up a system that creates barriers to entry.

MR. ERVIN: And to throw a totally gratuitous opinion out here, if you have a state that's got retail access, the idea that the CRR follows the load seems to me to be almost axiomatically correct.

Then lastly, the question of purely financial CRRs, to go back to a discussion that we had very early this morning, I tended to think that the notion of if you had a stalemate through the pricing mechanism of using CRR possession as a basis for resolving an impasse on who gets power made some sense. So I maybe can come out here without being totally critical of everything you've done. I thought that that was probably a reasonable way to deal with the problem.

MR. O'NEILL: We appreciate your support.

(Laughter.)

MR. ERVIN: Any time I can be helpful.

(Laughter.)

MR. ERVIN: But again, I do think that these things, while they are subject to my repeated caveat, probably reasonable in and of themselves, they clearly deserve more fleshing out, and the notion of commenting on them further strikes me as a good idea.

MS. FERNANDEZ: I mean, in terms of -- I agree that, I mean, a lot of these, we were writing them down very quickly. And I think if we had more than just the ten minutes or so on breaks, we probably would have longer -- actually have sentences as opposed to bullets on some of them, which would be more helpful.

But as sort of a general question, how specific should they be? I mean, there seemed to be in some areas a lot of interest in allowing regional flexibility. And as long as you're having kind of general principles that basically are saying there are certain -- the transition process is largely one of equity, and that you need to make certain it's done in an equitable way, but you also need to make certain that you don't build in certain inefficiencies for the future.

They are details more than kind of generalities, that the regions can then come up with ways of trying to implement them and put the burden there, rather than having the Commission come up with much more specific ones?

MR. ERVIN: I think I would personally tend to prefer to leave them fairly general, because I think the maximum amount of regional flexibility that you choose to allow is probably a good thing.

MR. THOMAS: I would agree. Just to take one specific example, I mean, on the allocation auction process, sure, tell them, tell the RTO that you have allocation followed by an auction, but then allow the rules on how those specific auctions are going to be carried to be defined at the RTO level. I think that makes a lot of sense.

MR. KAHAL: I would agree with Mr. Ervin that they should be kept fairly general. Also, it seems to me that you're calling them principles, but they are really kind of objectives, because I think that what you ultimately come up with is, you're going to meet them to a certain degree, and therefore it may make more sense to just call them objectives of the design process.

MS. FERNANDEZ: Okay.

MR. PROCTOR: Many of these principles that were laid out, seem to me to be principles related to transition.

And I think it would be helpful as well to lay out the principles or a vision, if you want to call it that, of what we're ultimately going to transition to.

That's one of the concerns that I have. These things tell us what we can do or what can be done up front. And the transition issues are really not easy. And I think it's going to take some time to work through those.

But I think people need to have a sense of direction of what they're working through to in order to put together regional proposals that work. On the other hand, I'm economist -- on the other hand, I realize that as people become more --

MR. O'NEILL: It's a cross you bear in life.

(Laughter.)

MR. PROCTOR: It's a curse.

(Laughter.)

MR. PROCTOR: As people become more familiar with the system, the ultimate objective may seem more reachable to them, as is familiarity --

MS. FERNANDEZ: I guess the question I'd have is that on some of these, if you're saying what the ultimate -- I mean, the ultimate objective is a competitive wholesale market.

If you start getting much more specific than that, I was wondering if you wouldn't get into some of the issues that -- and I can see that Commissioner Ervin might start commenting on that -- where you get into issues of is retail access vertical integration?

I think a lot of the more defining ones as to what you would want in a region will depend on what the states want to do on those issues.

MR. PROCTOR: For example, the loop flow issue, I mean, ultimately do you want that to work out? Ultimately, do you want to balance that? To me, it's a fundamental equity issue that doesn't exist today.

So, if you want that ultimately to be worked out, how do you want it to be worked out? We've got two RTOs talking, and talking -- maybe more than two -- talking about basing loop flows on some historical use.

And that may be fine in a transition, but ultimately maybe my loop flows on your system are worth a lot more than your loop flows on my system. And it's things like that that can, I think, ultimately bring down the objective of having a competitive wholesale market for electricity.

And I think that's where your focus is. I mean, I think the states will work on trying to get the retail aspects of it worked out.

MR. KAHAL: I have heard the term, end state, used quite a bit today, and it's problematic, I think, for states such as Arkansas, and maybe others in the Southeast. I think that we know where we are today. We think that we know what things are -- the structure is going to be like for electric service for the next few years.

We really don't know what the end state is; that is, we don't know what the preference is and whether, ultimately, Arkansas and other states are going to go to retail access or not.

Consequently, we just can't think in terms of end-state solutions and what the ultimate objective is, where we want to be at the end of this. We just see this as an ongoing process.

MR. LAWTON: I guess I would like to speak to the general principles. While it's not a perfect analogy, a good example of cooperative federalism really occurred under the old PRPA standards where there were eight principles that they put forward and the states basically followed them.

What the Federal Government got was a reasonably national policy that wasn't identical in every states, and what the states got was the ability to design things that worked well for them.

And so while it's not a perfect analogy, it seemed to work reasonably well.

MS. FERNANDEZ: Anything else to add?

(No response.)

MS. FERNANDEZ: We, unfortunately, don't have our attorneys here, so I think we have a little problem in committing to put something out. But I think it is a good suggestion and something we'll take back and see what we can do, and maybe can put out a list that's a bit more fleshed out to help people focus their comments.

And I'd like to thank the panel. We're actually ending right about on time. Thank you.

CHAIRMAN WOOD: Thank y'all.

(Whereupon, at 5:27 p.m., the technical conference was concluded.)